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Transcript Exhibit(s)

Docket #(s): E-01345A-11-0224

Exhibit # : RUC05-RUC07; SWEEP1-SWEEP3; S1, S3-S5

part 4 of 5

EXHIBIT
RUCO
5

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 18, 2011

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's analysis of Arizona Public Service Company's application for a permanent rate increase, filed with the Arizona Corporation Commission on June 1, 2011, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure falls just above the high side of the range of results obtained in RUCO's cost of equity analysis, and is 100 basis points lower than Arizona Public Service Company's proposed 11.00 percent cost of common equity.

Capital Structure – RUCO recommends that the Commission adopt Arizona Public Service Company's proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Cost of Debt – RUCO recommends that the Commission adopt RUCO's recommended cost of Long-term debt of 6.26 percent which is 12 basis points lower than the 6.38 percent cost of long-term debt being proposed by Arizona Public Service Company.

EXECUTIVE SUMMARY (Cont.)

Original Cost Rate of Return – RUCO recommends that the Commission adopt an 8.27 percent weighted average cost of capital as the original cost rate of return for Arizona Public Service Company This 8.27 percent figure is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 73 basis points lower than the 8.87 percent weighted average cost of capital being proposed by Arizona Public Service Company.

Fair Value Rate of Return – RUCO recommends that the Commission adopt a fair value rate of return of 6.10 percent which is RUCO's 8.27 percent original cost rate of return minus RUCO's recommended inflation adjustment of 2.18 percent. The method used by RUCO to arrive at this 6.10 percent figure is consistent with the methods adopted by the Arizona Corporation Commission in the prior UNS Gas, Inc. and UNS Electric, Inc. rate case proceedings.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to my direct testimony further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations based on my analysis of Arizona Public Service Company's ("APS" or the "Company") application for a permanent increase in rates ("Application").

Q. Is this your first case involving APS?

A. No. I've testified in two previous APS rate cases that have come before the Commission.

Q. Briefly describe APS and the Company's filing.

A. APS is based in Phoenix, Arizona and is the largest investor-owned electric utility in the state and serves customers in eleven of fifteen Arizona counties. According to the most recent Value Line Investment Survey ("Value Line") report on the Company, APS provides electricity to approximately 1.1 million customers comprised of 47.00 percent residential, 39.00 percent commercial, 5.00 percent industrial, and 9.00 percent other. APS' generating sources include coal, 37.00 percent; nuclear, 27.00 percent; natural gas, 12.00 percent; and purchased power, 24.00 percent. Fuel costs comprised 36.00 percent of the Company's revenues. The Company has approximately 7,200 employees.

APS' large service territory includes portions of the Phoenix metropolitan area in central Arizona; Flagstaff to the north; Parker and Yuma to the west; Holbrook to the east; and Ajo to the south. APS is a wholly owned subsidiary of Pinnacle West Capital Corporation ("Pinnacle West" or "Parent"), an Arizona corporation, also based in Phoenix, that is publicly traded on the New York Stock Exchange ("NYSE"). The Company has an ownership interest in the Palo Verde Nuclear Generating Station, located in Wintersburg approximately 50 miles west of downtown Phoenix, and operates the plant for itself and the other owners that provide electric service to customers in Southern California, New Mexico and West Texas.

Q. Has APS elected to perform a reconstruction cost new less depreciation study in this case?

A. Yes. APS elected to perform a reconstruction cost new less depreciation ("RCND") study and is proposing a fair value rate base ("FVRB") that is an average of the Company's original cost rate base ("OCRB") and its RCND rate base for ratemaking purposes. For this reason RUCO is recommending a fair value rate of return ("FVROR") to be applied to APS' FVRB.

Q. Please explain your role in RUCO's analysis of APS' Application.

A. I reviewed APS' Application and performed a cost of capital analysis to determine both an original cost rate of return ("OCROR") and a fair value rate of return ("FVROR") on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity (APS has no preferred stock) and my recommended cost of long-term debt. The recommendations contained in this testimony are based on information obtained from APS' Application, Company responses to data requests, and from market-based research that I conducted during my analysis.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case and will present RUCO's OCROR and FVROR recommendations.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into six sections. First, the introduction I have just presented and second, a summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of return for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which the Company is operating. Fourth, I will discuss my recommended capital structure and my recommended cost of long-term debt. Fifth, I will discuss my recommended weighted average costs of capital for both my recommended OCROR and FVROR. In the sixth and final section of my testimony, I will comment on the Company's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity Capital – I am recommending that the Commission adopt a 10.00 percent cost of common equity. This 10.00 percent figure is 23 basis points higher than the range of results obtained in my cost of equity analysis, and is 100 basis points lower than APS' proposed 11.00 percent cost of common equity.

Capital Structure – I am recommending that the Commission adopt APS' proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Cost of Debt – I am recommending that the Commission adopt a cost of long-term debt of 6.26 percent which is 12 basis points lower than the 6.74 percent cost of long-term debt being proposed by the Company.

Original Cost Rate of Return – I am recommending that the ACC adopt an 8.27 percent weighted average cost of capital as the original cost rate of return ("OCROR") for APS. This 8.27 percent figure is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 60 basis points lower than the 8.87 percent weighted average cost of capital being proposed by the Company.

Fair Value Rate of Return – I am recommending that the Commission adopt a fair value rate of return ("FVROR") of 6.10 percent which is my recommended 8.27 percent OCROR minus an inflation adjustment of 2.18 percent. The method I have used to arrive at this 6.10 percent figure is consistent with methods adopted by the Commission in prior rate case proceedings[1] and meets the fair value requirement of the Arizona

[1] UNS Electric, Inc., Decision No. 71914, dated September 30, 2010 and UNS Gas, Inc., Decision No. 71623, dated April 14, 2010

Constitution. It is also the same method recommended by RUCO witness Dr. Ben Johnson in the Southwest Gas Corporation rate case proceeding[2] that is now before the ACC.

Q Why do you believe that RUCO's recommended 8.27 percent OCROR and 6.10 percent FVROR are appropriate rates of return for APS to earn on its invested capital?

A. Both the OCROR and FVROR figures that I am recommending for APS meet the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the

[2] Docket No. G-01551A-10-0458

belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the <u>Bluefield</u> and <u>Hope</u> decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the <u>Bluefield</u> and <u>Hope</u> decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as APS, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for APS?

A. I am recommending a cost of equity of 10.00 percent (before any inflation adjustment used to arrive at a FVROR). My recommended 10.00 percent cost of equity figure falls just above the high side of the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded LDCs. The results of my DCF and CAPM analyses are summarized on page 3 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate the Company's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = \frac{D_1}{P_0} + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book

3 Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable.

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: g = DCF expected growth rate,

b = the earnings retention ratio,

r = the return on common equity,

s = the fraction of new common stock sold that

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [(BV) ÷ (MP)]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[7], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on a proxy group comprised of twenty publicly traded electric service providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of the Company?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although Pinnacle West Capital Corporation, APS' parent company, is publicly-traded on the NYSE, APS is not. Because of this situation, I used the aforementioned proxy that includes twenty electric utilities with similar

[7] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

risk characteristics as APS in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the electric utilities included in your proxy for APS?

A. Each of the electric utilities in my sample are tracked in the Value Line Investment Survey's ("Value Line") Electric Utility industry segment. Value Line follows electric utilities on a regional basis and issues quarterly updates on electric utilities located in the eastern, central and western portions of the U.S. All of the companies in the proxy are engaged in the provision of regulated electric services. Attachment A of my testimony contains Value Line's most recent evaluation on each of the twenty companies that I included in the electric proxy group that I used for my cost of common equity analysis.

Q. Are these the same electric providers included in the proxy used by APS' cost of equity witness?

A. With the exception of Pinnacle West Capital Corporation, the parent company of APS, these are the same electric providers used by William E. Avera, Ph.D., the Company's' cost of capital witness.

Q. Why did you exclude Pinnacle West Capital Corporation from your proxy group?

A. I excluded Pinnacle West Capital Corporation from my proxy group for two reasons. First, Value Line inadvertently omitted 2008 operating results for Pinnacle West Capital Corporation in their November 4, 2011 quarterly update on electric utilities located in the western region of the U.S. Upon discovering the omission I contacted Value Line to find out if a correction was going to be issued and was told by Mr. Paul Debbas that Value Line was not going to make a correction until their next quarterly update is published. A second, and possibly sounder, reason for omitting Pinnacle West Capital Corporation is simply that it is probably best not to include the parent of the company that is the subject of an analysis, since the object of the analysis is to determine a cost of equity figure for utilities with similar risk characteristics.

...

Q. Please explain your DCF growth rate calculations for the sample electric providers used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the electric companies included in my sample for an historical 5-year observation period from the beginning of 2006 to the end of 2010. Schedule WAR-5 also includes Value Line's projected 2011, 2012 and 2014-16 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the sample electric companies.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use Ameren Corp. (NYSE symbol AEE) as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described on pages 11 and 12 of my testimony) to multiply AEE's earned return on common equity by its earnings retention ratio for each year in the 2006 to 2010 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AEE's average internal growth rate of 2.18 percent over the 2006 to 2010 time frame reflects an up and down pattern of growth that ranged from a low of 1.03 percent in 2008 to a high of 3.82 percent during 2010. Value Line is predicting that growth will fall to 2.51 percent in 2011 and 2012 before increasing to 2.69 percent by the end of the 2014-16 time frame. After weighing Value Line's projections on earnings and dividend growth, I believe that a 3.00 percent rate of internal growth is within the realm of possibility for AGL (Schedule WAR-4, Page 1 of 2).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the number of shares outstanding for AEE increased from 206.60 million to 240.40 million from 2006 to 2010. Value Line is predicting that this level will increase from 244.00 million in 2011 to 256.00 million by the end of 2016. Based on this data, I believe that a 1.40 percent growth in shares is not unreasonable for AEE (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AEE is 5.70 percent (3.00 percent internal growth + 2.75 percent external growth – as calculated on Page 2 of Schedule WAR 4) and is shown on Page 1 of Schedule WAR-4.

Q. What is the average DCF dividend growth rate estimate for your sample utilities?

A. The average DCF dividend growth rate estimate for my sample is 5.59 percent as displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on your sample companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my growth estimates with the five-year projections of analysts at both Value Line and Zacks Investment Research, Inc. ("Zacks") (Attachment B). My 5.59 percent estimate exceeds Zacks' average long-term EPS projection of 2.37 percent and is 43 basis points higher than Value Line's growth projection of 5.16 percent (which is an average of EPS, DPS and BVPS). My 5.59 percent estimate is 252 basis points higher than the 3.07 percent average of Value Line's historical growth results and 108 basis points higher than the 4.01 percent average of the growth data published by both Value Line and Zacks. My 5.59 percent growth estimate is 186 basis points higher than Value Line's 3.73 percent 5-year compound historical average of EPS, DPS and BVPS. The estimates of analysts at Value Line indicate that investors are expecting somewhat lower growth than what I am estimating from the electric utility industry in the future. On balance, I would say my 5.59

percent estimate is somewhat more optimistic than the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends of my sample companies for the next twelve-month period that appeared in Value Line's most recent Ratings and Reports quarterly updates on the electric utility industry. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from September 12, 2011 to November 4, 2011, and the average dividend yield was 4.17 percent as exhibited on Schedule WAR-3.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the electric companies included in your sample?

A. As shown on Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.77 percent for the electric utilities included in my sample.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[9] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[9] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM is that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\ ß\ (r_m - r_f)\ ]$$

where:	k	=	the expected return of a given security,
	r_f	=	risk-free rate of return,
	ß	=	beta coefficient, a statistical measurement of a security's systematic risk,
	r_m	=	average market return (e.g. S&P 500), and
	$r_m - r_f$	=	market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

...

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments (Attachment C) will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yield on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated September 23, 2011 through November 11, 2011 (Attachment C). This resulted in a risk-free (r_f) rate of return of 0.97 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total risk to an investor, a good argument can be made that the yield on an instrument that matches the investment period of the asset being analyzed in the CAPM model should be used as the risk-free rate of return. Since utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2010 as the proxy for the market rate of return (r_m). For the risk-free portion of the risk premium component (r_f), I used the geometric mean of the total returns of intermediate-term government bonds for the same eighty-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 4.50 percent (9.90% - 5.40% = 4.50%). The market risk premium that results by using the arithmetic mean calculation is 6.40 percent (11.90% - 5.50% = 6.40%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of September 9, 2011 for the LDCs in my proxy. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the electric companies included in my sample ranged from 0.55 to 0.80 with an average beta of 0.75.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 4.32 percent. My calculation using an arithmetic mean results in an average expected return of 5.74 percent.

Q. What would be the expected return if a longer term 30-year U.S. Treasury bond were used as the risk free asset in the CAPM model?

A. During the eight week period that I relied on in my analysis, the yield on a 30-year U.S. Treasury bond declined from 3.27 percent to 3.01 percent. If a 3.01 percent eight-week average of 30-year U.S. Treasury bond yields were used in my CAPM model it would produce expected returns of 6.29 percent using a geometric mean, and 7.49 percent using an arithmetic mean. As I will discuss later in my testimony, the yields of long-term U.S. Treasury instruments are currently falling as a result of recent actions being undertaken by the U.S. Federal Reserve.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	**RESULTS**
DCF	9.77%
CAPM	4.32% – 5.74%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 4.32 percent to 9.77 percent. My final recommended cost of common equity figure is 10.00 percent which is just above the high end of the range of estimates shown above (Schedule WAR-1, Page 3).

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.00 percent cost of equity capital proposed by the Company is 100 basis points higher than the 10.00 percent cost of equity capital that I am recommending.

Q. How did you arrive at your final recommended 10.00 percent cost of common equity?

A. As just stated, my recommended 10.00 percent cost of common equity falls just above the high side of the range of estimates obtained from my DCF and CAPM analyses. As I will discuss in more detail in the next section of my testimony, my final estimate takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates), the current state of the national economy – which could be sliding back into recession. My final estimate also takes into consideration the U.S. Federal Reserve's recent decision not to raise interest rates anytime over the next two years. I also took into consideration information on Arizona's economy and current rate of unemployment in making my final cost of equity estimate. My final estimate also falls within the range of projected returns on book common equity that Value Line is projecting for the electric utility industry.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve, then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged

[11] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Disappointing economic data releases, since the beginning of 2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[12]

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers, and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates. Once again, the Fed managed to engineer a soft landing.

[12] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

Q. What has been the state of the economy since 2007?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the beginning of what is now being referred to as the Great Recession; the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[13] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages, and securities linked to them, forced the Fed to inject $24 billion in funds (raised through its open market operations) into the credit markets.[14] By Friday, August 17, 2007, after a

[13] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[14] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal,[15] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point

[15] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members believed would moderate during the economic slowdown).[16] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has

[16] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

been described as the worst financial crisis since the 1930's[17]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008.

Q. What is the current rate of inflation in the U.S.?

A. As can be seen on Schedule WAR-8, the current rate of inflation, as measured by the consumer price index, is at 3.90 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[18]

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. The FOMC has not raised interest rates to date. The Fed's plan to buy $600 billion of U.S. government bonds over an eight month period, known as quantitative easing stage two or QE2,[19] was completed during the summer of 2011. The attempt to drive down long-term interest rates

[17] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

[18] http://www.bls.gov/news.release/cpi.nr0.htm

[19] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010

and encourage more borrowing and growth by increasing the money supply has yet to stimulate the economy and fears of a double dip recession persist. At its August 9, 2011 meeting, the FOMC announced that it intended to keep interest rates at their current levels for at least the next two years warning that the economy would remain weak for some time but that the Fed is prepared to take further steps to shore it up.[20]

Q. Has the Fed taken any recent action, such as QE2, to stimulate the economy?

Yes. At the close of the FOMC's September meeting the Fed announced its decision to implement a plan that resembles a 1961 Federal Reserve program known as "Operation Twist".[21] Under this plan, the Fed will sell $400 billion in Treasury securities that mature within three years. The proceeds from these sales will then be reinvested into securities that mature in six to 30 years. This action would significantly alter the balance of the Fed's holdings toward long-term securities. In addition to selling off its shorter term Treasury holdings, the Fed will take the proceeds from its maturing mortgage-backed securities and reinvest them in other mortgage backed securities. For the past year, the Fed has been reinvesting that money into Treasury bonds, shrinking its mortgage portfolio. The overall

[20] Reddy, Sudeep and Jonathan Cheng "Markets Sink Then Soar After Fed Speaks" The Wall Street Journal, August 10, 2011

[21] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011

goal of the Fed's plan is to reduce long-term interest rates in the hope of boosting investment and spending and provide a shot in the arm to the beleaguered housing sector of the economy. During its most recent FOMC meeting held on November 1, 2011, the Fed decided not to make any changes to existing interest rates.

Q. Has there been any noticeable drop in long-term rates since the Fed announced its plan to purchase longer term Treasury instruments?

A. Yes. As I noted earlier in my testimony, the yield on the 30-year Treasury bond has from fallen from 3.27 percent to 3.01 percent since the latter part of September 2011.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since November of 2010.

As of November 4, 2011, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have dropped from their November 2010 levels. Longer term yields including the 5-year, 10-year and 30-year have all fallen from levels that existed a year ago. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[22], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists. The 5-year Treasury yield, used in my CAPM analysis, has decreased 23 basis points from 1.11 percent, in November 2010, to 0.88 percent as of November 2, 2011.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment C, as of November 2, 2011, 25/30-year A-rated utility bonds were yielding 4.12 percent (110 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 4.76 percent (down 103 basis points from a year earlier).

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[22] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

Q. What is the current outlook for the economy?

A. The current outlook on the economy is that a slide into recession appears to be unlikely but an outlook for slower growth persists. Value line's analysts offered this perspective in the November 11, 2011 edition of Value Line's Selection and Opinion publication:

> "**One by one, the markers pointing to a new recession are falling — at least in this country.** Recent data, for example, affirm that consumer spending, manufacturing orders, and auto sales are pressing higher, while other reports confirm that industrial production and business investment are rallying. Those still calling for a recession, therefore, are getting less and less of an audience."

Value Line's analysts went on to say:

> "**The U.S. upturn could move onto a slower track going forward,** with growth — which rose to 2.5% in the third quarter — perhaps easing to less than 2% this period. Thereafter, there may be some gradual firming in 2012, with growth possibly averaging 2%, or so. Clearly, though, this forecast is tenuous due to uncertainty in Europe, where a recession seems more likely."

Value Line's analysts also stated:

> "**The year ahead holds numerous questions.** First, there is Europe, which is in flux, as prior headlines proclaiming a resolution of the debt crisis now look a bit premature. Then, there are Federal Reserve policies, which are fluid and likely to evolve further, as the central bank seeks a balance between promoting faster growth and containing inflation. Also, there are questions about housing and personal income, both of which are under strain. Finally, there's the likelihood of slower growth in China, which would add to global strains. All of this implies that a stronger showing by our economy in 2012 is unlikely."

Value Line's analysts further went on to say:

> "**Earnings season is now in the books**, and it has been a respectable one for the most part. However, there were fewer fireworks on the upside than in prior quarters, as profit matchups became more difficult after two years of easy growth. We also

> think earnings will press forward in the final quarter, but more modestly."

Q. How are electric utilities such as APS faring in the current economic environment?

A. In the November 4, 2011 quarterly update on the Electric Utility (West) Industry, Value Line analyst Paul E. Debbas, CFA had this to say:

> "Electric utility stocks are known for outperforming the broader market averages in a down market. So far in 2011, this has proven to be the case. The Value Line Geometric Average is down 12% this year, while the Value Line Utility Average is up 2%. When dividends are considered, the relative out performance of this group is even greater. This had made the equities in this industry relatively less attractive, however. In fact, some issues, such as Pinnacle West, are trading around the middle of th eir 2014-2016 Target Price Range. F or a utility stock, this is often a sign that it has become overvalued."

Also Included in Value Line's November 4, 2011 issue is its ranking of each state's regulatory climate, plus that of the District of Columbia and the Federal Energy Regulatory Commission ("FERC"). Value Line ranks states as above average, average and below average. Interestingly, Arizona was ranked as average along with California, Delaware, District of Columbia, Florida, Georgia, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, Texas, Virginia, Washington and Wyoming.

...

Q. How has Arizona fared in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery.[23] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties. As of this writing RealtyTrac still ranks Arizona as having the third highest foreclosure rate in the country with one in every ninety-three housing units receiving a foreclosure filing in the third quarter.[24]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on October 20, 2011, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[25] the seasonally adjusted unemployment rate for Arizona dropped two tenths of a percentage point

[23] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011

[24] Millar, DiAngelea, "RealtyTrac: Arizona home foreclosures down sharply," Phoenix Business Journal, October 13, 2011.

[25] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/

from 9.3% in August, to 9.1% in September. At the time that this information was compiled, Arizona's rate of unemployment mirrored the U.S. unemployment rate which remained unchanged at 9.1% for the third consecutive month. In September 2010 the U. S. rate was 9.6% and Arizona's rate was 9.8%[26] as can be seen below:

Arizona, U.S. Economic Indicators
Unemployment Rate (Seasonally Adj.)

	Sep '11	Aug '11	Sep '10
United States	9.1%	9.1%	9.6%
Arizona	9.1%	9.3%	9.8%
Arizona unadjusted rate	8.9%	9.4%	9.8%

More recent information on the national rate of unemployment, released by the U.S. Department of Labor on November 4, 2011, has pegged U.S. unemployment at 9.00 percent.

According to the October 20, 2011 Arizona Department of Administration's Office of Employment and Population Statistics report, the September 2011 rates of unemployment for the counties that are served by APS were as follows:

Selected County Unemployment Rates - September 2011

Apache	15.0%
Cochise	8.2%
Coconino	7.3%
Gila	9.7%
La Paz	9.5%
Maricopa	7.9%
Navajo	14.0%

[26] U.S. Bureau of Labor Statistics Economic News Release dated June 3, 2011 http://www.bls.gov/news.release/empsit.nr0.htm

Pima	8.0%
Pinal	10.6%
Yavapai	9.4%
Yuma	27.0%

Q. After weighing the economic information that you've just discussed, do you believe that the 10.00 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 10.00 percent cost of equity capital, which is 524 basis points higher than the current 4.76 percent yield on a Baa/BBB-rated utility bond, will provide APS with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally, in Arizona, and in the counties served by APS), and the Fed's decision to keep interest rates at their current levels over the next two years are all taken into consideration. As I noted earlier, the <u>Hope</u> decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis, which is on the high side of the range of results I obtained from both the DCF and CAPM models, has produced such a return.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Please describe the Company-proposed capital structure.

A. The Company-proposed end of test year capital structure is comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Q. How does the Company-proposed capital structure compare with the capital structures of the electric companies that comprise your sample?

A. The Company-proposed capital structure containing 53.94 percent common equity is somewhat higher in equity than the capital structures of the electric companies in my sample, which had an average of 45.70 percent common equity, and would be perceived by investors as having somewhat lower risk overall. APS' 46.06 percent level of long-term debt is lower than the average of 53.60 percent in my sample and would be perceived as having a lower level of financial risk. Overall I would say that APS' capital structure is fairly well balanced.

Q. What capital structure are you recommending for APS?

A. I am recommending that he Commission adopt the Company-proposed capital structure comprised of 53.94 percent common equity and 46.06 percent long-term debt.

Q. What cost of long-term debt are you recommending for APS?

A. I am recommending that the Commission adopt a cost of Long-term debt of 6.26 percent which, based on my calculation of the Company's various outstanding debt instruments, is 12 basis points lower than the 6.38 percent cost of long-term debt being proposed by APS.

WEIGHTED COST OF CAPITAL AND FAIR VALUE RATE OF RETURN

Q. What original cost weighted average cost of capital are you recommending for APS?

A. Based on my recommended capital structure, comprised of 53.94 percent common equity and 46.06 percent long-term debt, I am recommending an original cost weighted average cost of capital of 8.27 percent (Schedule WAR-1, Page 1). This is the weighted average cost of my recommended cost of 10.00 percent common equity and my recommended 6.26 percent cost long-term debt. My 8.27 percent weighted average cost of capital is also the OCROR to be applied to APS' original cost rate base.

Q. What fair value rate of return are you recommending for APS?

A. I am recommending a FVROR of 6.10 percent (Schedule WAR-1, Page 1) which is my OCROR minus an inflation factor of 2.18 percent (Schedule WAR-1, Page 4). My recommended FVROR satisfies the fair value requirement of the Arizona Constitution which the Commission must follow when setting rates for investor owned utilities such as APS.

Q. Why are you recommending a FVROR that is different from your OCROR?

A. Because APS elected not to use the Company's original cost rate base ("OCRB") as its fair value rate base ("FVRB") in this case. Instead, APS performed a reconstruction cost new less depreciation ("RCND") study to restate the value, or reproduction cost, of the Company's OCRB. As is the normal ratemaking practice in Arizona, the Company averaged the values of its OCRB and its RCND rate base to arrive at a FVRB that is higher than the OCRB. This is because the value of the FVRB reflects the impact of inflation and other factors which tend to contribute to an upward growth in value over time. Since the difference in the value of the OCRB and the FVRB represents inflation, as opposed to additional investor supplied capital, an OCROR which includes an inflation component cannot be applied to the FVRB. To do so would result in a double counting of inflation. For this reason it is necessary to remove the inflation component that is included in the OCROR.

Q. Does your recommended FVROR satisfy the requirements for determining a FVROR that resulted from the Commission's Chaparral City Water Company remand decision, which established the need to remove the inflation component from an OCROR?

A. Yes. On July 28, 2008, the Commission issued Decision No. 70441, in which stated the following:

> Our previous method was a shorthand method of ensuring that inflation would only influence one piece of the ratemaking formula - the rate of return. However, the Court of Appeals has made it clear that, under our constitution, the "inflation component" belongs in the FVRB. Accordingly, in order to avoid over-counting the effect of inflation, it is necessary for us to ensure that the rate of return does not also carry an inflation component. [Decision No. 70441, p. 33]

Q. How did you remove the inflation component from your OCROR?

A. By reducing my recommended costs of common equity and long-term debt by an inflation factor of 2.18 percent. This produced my recommended FVROR of 6.10 percent. The method that I have used in this case produces a FVROR that is comparable to the FVROR calculated for UNS Electric, Inc. in a prior rate case proceeding. In that case the Commission adopted a method that reduced the OCROR by an inflation factor that was recommended by RUCO.[27] The Commission had previously used the same method in a rate case proceeding for UNS Electric, Inc.'s sister utility, UNS Gas, Inc. Under the Commission's adopted methodology in the prior UNS Inc. cases, my recommended OCROR of 8.27 percent would be reduced by my recommended 2.18 percent inflation factor – thus resulting in a FVROR of 6.10 percent. The method that I have used in this case, which removes the inflation factor from both my recommended cost of equity and recommended cost of debt, produces an identical 5.96 percent FVROR.

---

[27] Decision No. 71914, dated September 30, 2010

Q. How did you calculate your inflation factor of 2.18 percent?

A. By using the same RUCO methodology that produced an inflation factor similar to what the Commission relied on in the prior UNS Electric, Inc. case cited above. As can be seen on Page 4 of Schedule WAR-1, my recommended 2.18 percent inflation factor represents the difference between Treasury Inflation-Protected Securities ("TIPS") and comparable securities issued by the U.S. Treasury with similar liquidity and duration over a nine year period.

Q. How does your FVROR compare to the FVROR being recommended by APS?

A. My recommended FVROR of 6.10 percent is 30 basis points lower than the 6.47 percent FVROR being proposed by APS.

Q. What inflation factor does APS propose?

A. APS does not reduce its proposed cost of common equity by an inflation factor. As stated on page 4 of his direct testimony, APS' cost of equity witness Dr. William E. Avera states that the Company-proposed 11.00 percent cost of common equity needs no adjustment since his DCF and CAPM results were obtained using analysts' forward looking estimates based on current market values.

Q. Do you agree with Dr. Avera's rationale as to why no inflation adjustment is needed to reduce the Company-proposed OCROR?

A. No. I do not since analysts' forward looking estimates would only take future expected inflation into account. Relying on analysts' forecasted estimates does not address the impact of inflation and other factors which tend to contribute to an upward growth in the value of plant assets over time which is reflected in the Company's RCND rate base which I explained above.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

Q. Have you reviewed APS' testimony on the Company-proposed cost of equity capital?

A. Yes, I have reviewed the testimony prepared by Dr. William E. Avera.

Q. What issues does Dr. Avera address in his cost of equity testimony?

A. In addition to addressing the cost of common equity issues in this case, Dr. Avera also addresses the capital structure, credit worthiness, and attrition issues that APS' has raised in its Application.

...

Q. Please compare the Company-proposed cost of equity with your recommended cost of equity.

A. The Company is recommending a cost of equity capital of 11.00 percent which is 100 basis points higher than my recommended 10.00 percent cost of equity.

Q. Have you studied the specific methods that Dr. Avera used to derive the Company-proposed cost of equity capital?

A. Yes.

Q. What methods did Dr. Avera use to arrive at his cost of common equity for APS?

A. Dr. Avera used the DCF and CAPM methods to estimate APS' cost of common equity.

Q. Can you provide a comparison of the results derived from Dr. Avera's models and yours?

A. Yes. The following portion of my testimony will compare and contrast the results of our DCF and CAPM analyses.

...

DCF Comparison

Q. Please compare the results of Dr. Avera's DCF analysis and the results of your DCF analysis.

A. Dr. Avera presented the results of two DCF analyses, one that relied on a sample of regulated electric utilities and the other on unregulated industrials. His DCF analysis using a sample of regulated utilities produced estimates ranging from 9.50 percent to 11.20 percent and his DCF analysis using a sample of unregulated industrials, or non-utilities, produced estimates ranging from 11.90 percent to 12.50 percent. My DCF analysis, which relied on a sample with all but one (Pinnacle West Capital Corporation, the parent of APS) of the regulated electric utilities included in Dr. Avera's sample, produced a final estimate of 9.77 percent.

Q. Why didn't you perform an analysis that included unregulated industrials?

A. Quite simply because I believe that a sample of regulated electric utilities that face the same types of risks and operating conditions that APS does is an appropriate sample. Furthermore the results obtained by Dr. Avera's non-utilities sample clearly demonstrate that these firms are much more riskier than regulated utilities.

...

Q. What was the difference between Dr. Avera's dividend yield results for electric utilities and your dividend yield results?

A. Dr. Avera's DCF analysis of regulated electric utilities produced an average dividend yield of 4.53 percent as opposed to my average dividend yield of 4.17 percent. I attribute the majority of the 36 basis point difference to higher closing stock prices that I recorded during my more recent 8-week observation period since there is not that much difference in the annualized dividends paid by our respective sample companies.

Q. Please compare your respective DCF growth estimates (g) for electric utilities.

A. Dr. Avera's electric utilities DCF analysis produced average growth estimates of 4.97 percent to 6.67 percent compared to my 5.59 percent estimate. However, as I will discuss later, Dr. Avera's estimates ignore high and low estimates obtained from his model.

Q. Were there any differences in the way that you conducted your DCF analysis and the way that Dr. Avera conducted his?

A. Yes. Dr. Avera also relied on projections from IBES in addition to my reliance on Value Line and Zacks. He also performed a br + sv type calculation similar to what I have done. The IBES growth projections of 5.83 percent were 24 basis points higher than my 5.59 percent average growth estimate. However, I will point out that Dr. Avera's DCF analysis placed no emphasis on the past performance of the electric utilities in his sample and focused entirely on analysts' future projections to estimate the growth component (g) of the DCF model. While I agree that the estimation of an appropriate cost of common equity is a forward looking process, I believe that past performance should not be ignored entirely. Consideration of utilities' past performance should serve as a useful check on the reasonableness of analysts' future expectations. In addition to my points above, Dr. Avera eliminates high and low results (i.e. outliers) from his DCF results in order to arrive at his final DCF cost of common equity estimate.

Q. Have you removed such outliers from your analysis?

A. No. While I will admit that several of my sample electric utilities had results that could be classified as being extremely high or low, I have decided not to ignore them.

CAPM Comparison

Q. Please compare the results of Dr. Avera's CAPM analysis and the results of your CAPM analysis.

A. Dr. Avera's CAPM analysis produced an estimate of 11.40 percent for his sample of electric utilities and an estimate of 10.00 percent for his sample of unregulated industrials. His estimates are 708 basis points to 568 basis points higher than my 4.32 percent CAPM estimate that uses a geometric mean and are 566 basis points to 426 basis points higher than my 5.74 percent CAPM estimate that uses an arithmetic mean. When compared to my CAPM estimates that relied on an eight-week average 30-year U.S. Treasury bond yield as the risk free rate of return, Dr. Avera's utility sample estimates are 511 basis points higher than my 6.29 percent estimate using a geometric mean, and 391 basis points higher than my 7.49 percent estimate using an arithmetic mean. Dr. Avera's 11.40 percent utility sample estimate exceeds the recent yield of 4.67 percent on a Baa/BBB-rated utility bond yield by 673 basis points.

Q. **What are the main reasons for Dr. Avera's higher CAPM results?**

A. The much higher inputs that include his risk free rate of return and Dr. Avera's market risk premium which utilized his own method for calculating the return on the market as opposed to relying on the more established method of relying on historical market data published in Morningstar. Dr. Avera CAPM expected return estimates also include a size adjustment of 0.074 percent for his utility sample and negative 0.37 percent for his unregulated industrials.

Q. Please describe the differences in the way that you conducted your CAPM analysis and the way that Dr. Avera conducted his?

A. As noted above, there are two main differences between Dr. Avera's CAPM analysis and mine. The first difference involves Dr. Avera's use of a 4.50 percent one month average of the higher yields of 30-year Treasury bonds as opposed to the more recent 8-week average yields of a 5-year Treasury instrument that I relied on for the risk-free rate of return. The second difference involves his market risk premium. Dr. Avera's market risk premium is the 12.8 percent sum of yields and growth rates of S&P 500 dividend paying firms recorded on January 28, 2011 and February 23, 2011 respectively minus the aforementioned 4.50 percent risk free rate, used by Dr. Avera, as opposed to the SBBI data that I relied on that encompassed a much broader period of the U.S. economy between 1926 and 2010. Dr. Avera's method results in a market risk premium of 8.30 percent (12.80% - 4.50% = 8.30%) as opposed to my risk premiums of 4.50 percent and 6.40 percent based on a geometric and arithmetic mean respectively.

Q. Please compare the differences in the risk free rates that you and Dr. Avera relied on.

A. Dr. Avera's risk free rate is 4.50 percent as opposed to my risk free rate of 0.97 percent. As I noted earlier in my testimony, I believe a 5-year treasury instrument is more appropriate since Arizona utilities generally apply for rates every three to five years on average. Dr. Avera's chosen 30-year Treasury bond instrument is currently yielding 3.01 percent (Attachment C).

Q. Did Dr. Avera use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However, Dr. Avera's utility sample had an average Value Line beta of 0.74 as opposed to my average Value Line beta of 0.75 (using a sample that excluded Pinnacle West Capital Corporation). Dr. Avera's beta for unregulated industrials was 0.71.

Q. What is the beta of Pinnacle West Capital Corporation, the parent of APS?

A. Pinnacle West Capital Corporation has a Value Line beta of 0.70 which is lower than Dr. Avera's average utility sample beta of 0.74 and my average beta of 0.75. This indicates that APS' parent company is not as risky as the average of our respective sample electric utilities.

Q. How did Dr. Avera arrive at his final 11.00 percent cost of equity capital for APS?

A. Dr. Avera's final cost of equity estimate of 11.00 percent falls within the 9.50 percent to 12.50 percent range of results obtained from his DCF and CAPM models using two sample groups comprised of regulated electric utilities and unregulated industrials.

...

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Dr. Avera or any other witness for APS constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on APS?

A. Yes, it does.

Qualifications of William A. Rigsby, CRRA

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona-American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Corporation	T-01051B-03-0454	Renewed Price Cap
Chaparral City Water Company	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review
Southwest Gas Corporation	G-01551A-04-0876	Rate Increase
Arizona-American Water Company	W-01303A-05-0405	Rate Increase
Black Mountain Sewer Corporation	SW-02361A-05-0657	Rate Increase
Far West Water & Sewer Company	WS-03478A-05-0801	Rate Increase
Gold Canyon Sewer Company	SW-02519A-06-0015	Rate Increase
Arizona Public Service Company	E-01345A-05-0816	Rate Increase
Arizona-American Water Company	W-01303A-05-0718	Transaction Approval
Arizona-American Water Company	W-01303A-05-0405	ACRM Filing
Arizona-American Water Company	W-01303A-06-0014	Rate Increase
UNS Gas, Inc.	G-04204A-06-0463	Rate Increase
Arizona-American Water Company	WS-01303A-06-0491	Rate Increase
UNS Electric, Inc.	E-04204A-06-0783	Rate Increase
Arizona-American Water Company	W-01303A-07-0209	Rate Increase
Tucson Electric Power	E-01933A-07-0402	Rate Increase
Southwest Gas Corporation	G-01551A-07-0504	Rate Increase
Chaparral City Water Company	W-02113A-07-0551	Rate Increase
Arizona Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
UNS Gas, Inc.	G-04204A-08-0571	Rate Increase
Arizona Water Company	W-01445A-08-0440	Rate Increase
Far West Water & Sewer Company	WS-03478A-08-0608	Interim Rate Increase
Black Mountain Sewer Corporation	SW-02361A-08-0609	Rate Increase
Global Utilities	SW-02445A-09-0077 et al.	Rate Increase
Litchfield Park Service Company	SW-01428A-09-0104 et al.	Rate Increase
UNS Electric, Inc.	E-04204A-09-0206	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-08-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Southwest Gas Corporation	G-01551A-10-0458	Rate Increase
Arizona-American Water Company	W-01303A-10-0448	Rate Increase
Arizona-American Water Company	W-01303A-11-0101	Reorganization
Bermuda Water Company, Inc.	W-01812A-10-0521	Rate Increase
UNS Gas, Inc.	G-04204A-11-0158	Rate Increase

ATTACHMENT A

All of the major electric utilities located in the western region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 5.

In this Issue, we present our rankings of regulatory climates. We have made one change from the previous table, and some other rankings bear watching.

Electric utility stocks are known for their relative outperformance when the broader market averages are down, and 2011 has illustrated this.

INDUSTRY TIMELINESS: 27 (of 98)

Ranking The Regulators

Occasionally, we show a list of each state's regulatory climate, plus that of the District of Columbia and the Federal Energy Regulatory Commission (FERC). Even in states that have undergone partial deregulation of the electric industry, the distribution function is still under the oversight of the regulatory commission. So, this is relevant for every electric utility equity under our coverage. This has become even more important in recent years because rate applications are on the rise. Some companies, such as Great Plains Energy and Duke Energy, have completed or are building large capital projects that need to be placed in the rate base. Others, such as *Avista Energy* and Ameren, are filing more frequently in order to reduce the effects of regulatory lag (i.e., rising costs that aren't reflected in customers' rates).

It is important to understand that our rankings don't just look at regulatory commissions. Other aspects of government, such as the governor, attorney general, legislature, and courts are also considered.

The following listing excludes Alaska, Maine, Nebraska, Rhode Island, Tennessee, and Utah. This is either because there is little or no presence of investor-owned electric companies or because the state's investor-owned electric utilities are subsidiaries of foreign companies that we do not cover.

• *Above Average:* Alabama, Colorado, Idaho, Indiana, Massachusetts, Ohio, South Carolina, South Dakota, Wisconsin, FERC.

• *Average:* Arizona, California, Delaware, District of Columbia, Florida, Georgia, Hawaii, Iowa, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Pennsylvania, Texas, Virginia, Washington, Wyoming.

• *Below Average:* Arkansas, Connecticut, Illinois, Maryland, New York, Oregon, Vermont, West Virginia.

We have raised South Carolina from Average to Above Average. The state's Base Load Review Act enables utilities to recover construction work in progress for base-load generating facilities. Without this law, SCANA's electric utility subsidiary, South Carolina Electric & Gas, would not be building two nuclear units. We are also considering raising Oregon's regulatory climate to Average. The state government took a positive step earlier this year when it rescinded a tax law that was unique to utilities in the state.

We have not lowered any rankings, but are looking at Massachusetts and FERC. In Massachusetts, the proposed merger between NSTAR and Northeast Utilities has become highly politicized. If the deal fails to win regulatory approval, we will probably lower the regulatory climate a notch. For several years, FERC has granted very healthy returns on equity for transmission investment in order to encourage utilities to boost their spending on electric transmission. However, the question has been raised (by the payers of transmission rates) of whether the incentives are *too* generous. We won't consider cutting FERC's ranking unless it starts cutting the allowed ROEs for transmission. This is of special concern to ITC Holdings, the sole publicly traded transmission-only utility.

Conclusion

Electric utility stocks are known for outperforming the broader market averages in a down market. So far in 2011, this has proven to be the case. The Value Line Geometric Average is down 12% this year, while the Value Line Utility Average is up 2%. When dividends are considered, the relative outperformance of this group is even greater. This had made the equities in this industry relatively less attractive, however. In fact, some issues, such as *Pinnacle West*, are trading around the middle of their 2014-2016 Target Price Range. For a utility stock, this is often a sign that it has become overvalued.

Paul E. Debbas, CFA

Composite Statistics: ELECTRIC UTILITY INDUSTRY

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	**320**	**335**	Revenues ($bill)	**385**
27.4	27.7	27.7	30.1	**29.0**	**31.0**	Net Profit ($bill)	**37.0**
33.1%	33.5%	32.2%	34.2%	**34.0%**	**34.5%**	Income Tax Rate	**34.5%**
6.3%	7.8%	9.2%	8.5%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
50.9%	53.6%	52.4%	52.2%	**51.0%**	**50.5%**	Long-Term Debt Ratio	**50.0%**
48.0%	45.4%	46.6%	47.0%	**48.5%**	**49.0%**	Common Equity Ratio	**49.5%**
467.8	514.0	554.1	585.7	**575**	**605**	Total Capital ($bill)	**695**
505.5	554.4	594.5	640.1	**640**	**680**	Net Plant ($bill)	**780**
7.5%	6.9%	6.5%	6.6%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.0%**
11.9%	11.6%	10.5%	10.7%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.5%**
12.1%	11.8%	10.6%	10.8%	**10.0%**	**10.0%**	Return on Com Equity	**10.5%**
5.5%	4.9%	4.2%	4.5%	**4.0%**	**4.0%**	Retained to Com Eq	**4.5%**
55%	58%	61%	59%	**60%**	**61%**	All Div'ds to Net Prof	**59%**
16.9	15.4	12.5	12.9	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.90	.93	.83	.82	*Value Line*		Relative P/E Ratio	**.90**
3.2%	3.8%	4.8%	4.5%	*estimates*		Avg Ann'l Div'd Yield	**4.3%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2008	2009	2010
% Change Retail Sales (kwh)	-1.1	-5.4	+3.6
Average Indust. Use (mwh)	1529	1446	1530
Avg. Indust. Revs. per kwh (¢)	6.66	6.46	6.56
Capacity at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+.1	-.2	+1.6
Fixed Charge Coverage (%)	311	280	305

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

INDUSTRY TIMELINESS: 5 (of 98)

All of the major electric utilities located in the central region of the United States are reviewed in this Issue; eastern electrics, in Issue 1; and the remaining utilities, in Issue 11.

Last month, the Edison Electric Institute spoke about various issues that the electric utility industry is facing. We discuss the industry's concerns.

We note the ways in which the weather has affected electric utilities so far this year.

Electric utility stocks have outperformed the broader market averages, and have been less volatile, during the market turmoil of the past several weeks.

What's On EEI's Mind

The Edison Electric Institute (EEI), an industry group representing investor-owned electric utilities, made a presentation to security analysts last month. It is probably not surprising that the industry is facing issues such as more stringent rules from the U.S. Environmental Protection Agency. On the other hand, investors might be surprised to learn that the Dodd-Frank law, which is targeted for commercial banks, might wind up affecting utilities, too.

Capital spending is increasing. The expenditures of investor-owned electric utilities are projected at over $80 billion a year from 2011 through 2015. (As recently as in 2005, this figure was below $50 billion.) Over the next 20 years, EEI projects that the industry will spend $1.5 trillion-$2.0 trillion on infrastructure, some $200 billion of which will be used to address environmental issues.

This increase is occurring even though the industry is no longer seeing the demand growth that it did not too long ago. The ongoing sluggishness of the economy is one factor. Conservation measures and the increased energy efficiency of appliances are another. What's more, as electric rates are raised to recover higher expenses and place capital projects in the rate base, some price elasticity is evident.

The Dodd-Frank Act, which was enacted in 2010, might also wind up affecting utilities, which trade in power and gas. Many rules will be finalized in 2012 by the U.S. Commodity Futures Trading Commission. Among these are the rules for swaps and swap dealers. If utilities are treated as "dealers," this would cause compliance burdens for the industry. EEI is asking for an end-user exemption that would prevent utilities from having to post margin requirements for transactions.

In July, the Federal Energy Regulatory Commission (FERC) issued a rule concerning electric transmission. Planning and cost allocation have been thorny issues for a while. FERC is trying to encourage competition for transmission projects, although the incumbent utilities will still have the right of first refusal for certain projects. Regional transmission organizations will have to apply the new rules. This is of particular interest for *ITC Holdings*, the sole publicly traded transmission-only utility.

Weather Impacts

The weather always affects electric utilities, but this year has seen some more significant impacts than usual. Hurricane Irene caused power outages for millions of customers, and hurricane season is not yet over. Most notably, the service territory of *Empire District Electric* was devastated by a tornado that hit Joplin, Missouri in May. Initially, the loss of load didn't hurt results much (due in part to hotter-than-normal summer weather), but that's not to say that there won't eventually be any impact.

Many parts of the United States experienced summer weather conditions that were much hotter than normal. Earnings at *OGE Energy*, the parent company of Oklahoma Gas and Electric, will benefit from favorable weather patterns in 2011. Other utilities are likely to post strong third-quarter profits, too.

Flooding in the Midwest will prevent Kansas City Power & Light, the largest subsidiary of *Great Plains Energy*, from receiving as much coal as usual. Thus, the utility will have to use more-costly sources of power (and doesn't have a fuel adjustment mechanism in Missouri). This will hurt its profits in the second half of 2011.

Conclusion

Electric utility stocks have long been known for their defensive characteristics, and this has been evident of late. When the market experienced wide day-to-day swings in August, utility stocks weren't as volatile as the overall market. So far in 2011, the Value Line Utility Average is relatively unchanged, while the Value Line Composite Average has decreased 14%. Most electric utility stocks offer attractive dividend yields, but we caution investors that many are trading within their 2014-2016 Target Price Range.

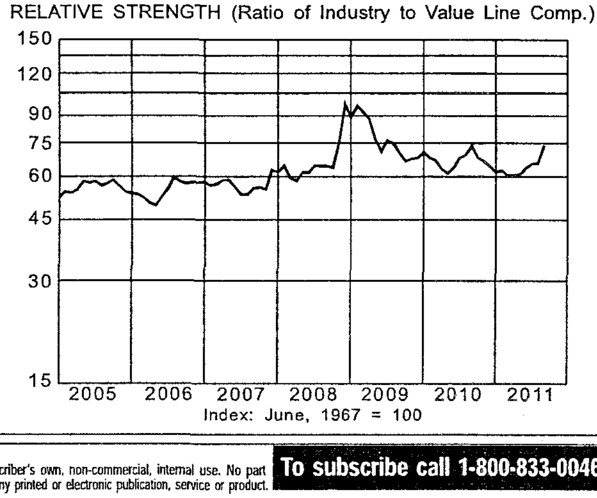
Paul E. Debbas, CFA

Composite Statistics: Electric Utility Industry

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	*320*	*335*	Revenues ($bill)	*385*
27.4	27.7	27.7	30.1	*29.0*	*31.0*	Net Profit ($bill)	*37.0*
33.1%	33.5%	32.2%	34.2%	*34.0%*	*34.5%*	Income Tax Rate	*34.5%*
6.3%	7.8%	9.2%	8.7%	*7.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
50.9%	53.6%	52.4%	52.2%	*51.0%*	*50.5%*	Long-Term Debt Ratio	*50.0%*
48.0%	45.4%	46.6%	47.0%	*48.5%*	*49.0%*	Common Equity Ratio	*49.5%*
467.8	514.0	554.1	585.7	*575*	*605*	Total Capital ($bill)	*695*
505.5	554.4	594.5	640.1	*640*	*680*	Net Plant ($bill)	*780*
7.5%	6.9%	6.5%	6.6%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.9%	11.6%	10.5%	10.7%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.5%*
12.1%	11.8%	10.6%	10.8%	*10.0%*	*10.0%*	Return on Com Equity	*10.5%*
5.5%	4.9%	4.2%	4.5%	*4.0%*	*4.0%*	Retained to Com Eq	*4.5%*
55%	58%	61%	59%	*61%*	*62%*	All Div'ds to Net Prof	*58%*
16.9	15.4	12.5	12.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.5*
.90	.93	.83	.83			Relative P/E Ratio	*.90*
6.3%	3.8%	4.8%	4.5%			Avg Ann'l Div'd Yield	*4.3%*

Electric Utility

RELATIVE STRENGTH (Ratio of Industry to Value Line Comp.)



Index: June, 1967 = 100

All the major utilities in the eastern region of the U.S. are reviewed in this Issue. Those serving the central region will be found in Issue 5. All of the western providers are covered in Issue 11.

Needless to say, it's been a tumultuous couple of months for equity market investors. A slew of mixed economic and political data has sent stocks on a roller coaster ride, including a series of 300+ point swings on the Dow Jones Industrial Average in early August. During these volatile times, investors tend to seek out safe havens for their money, which as far as equities are concerned, usually leads them to the utility sector. The industry's relative stability has been highlighted considerably over the past twelve months. Year-to-date, the Value Line Utility Average has remained relatively flat, rising a modest .3%, while the Value Line Geometric Average is down 12.1%.

In this report, we touch on pending merger & acquisition activity among Issue 1 utilities. We also point out some attractive dividend plays for investors seeking income.

INDUSTRY TIMELINESS: 38 (of 98)

Merger/Acquisition Updates

Progress/Duke: *Duke Energy's* $14 billion buyout of rival *Progress Energy* remains scheduled for a late-2011 completion. The combination recently gained regulatory approval in Kentucky but still needs clearance from the commissions in North Carolina and South Carolina. Shareholder votes for both companies were to be held shortly after this issue went to press. As mentioned in previous reports, a successful completion would create the largest electric utility in the United States based on customers served (about 7.1 million).

Northeast/NSTAR: *Northeast Utilities* $4.5 billion acquisition of *NSTAR* appears to be hitting a few speed bumps. Although each company's shareholders and the Federal Energy Regulatory Commission have approved the deal, gaining state approvals appears to be a bit more challenging. Political opposition has raised concerns in Massachusetts, while uncertainty regarding jurisdiction issues in Connecticut has done the same. Even with all of this, the companies remain optimistic that the deal will be completed sometime during the fourth quarter of 2011.

Exelon/Constellation: *Exelon Corp's* $7.9 billion bid to acquire *Constellation Energy* is currently pending. The deal must still be approved by each company's respective shareholders, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, as well as state regulators in Maryland and New York. However, the situation in Maryland has become somewhat worrisome in the early stages, as intervenors are asking for much larger concessions than *Exelon* has agreed to provide. Despite this, the companies are still targeting an early-2012 completion.

Central Vermont/Gaz Metro: *Central Vermont* has entered into a definitive agreement to be acquired by Canadian-based *Gaz Metro Limited* for $35.25 a share, terminating its previous $35.10-a-share agreement with *Fortis Inc.* The offer from *Gaz Metro* represented a 45% premium over CV's closing price prior to the announcement with Fortis. The deal is still subject to regulatory and shareholder approvals.

Dividends

At present, stocks in the Electric Utility industry are yielding 4.4% on average, well above the *Value Line Investment Survey* average (2.3%). Income-oriented investors should have little trouble finding attractive options within the group. In Issue 1, several are currently returning over 5% annually: *Pepco Holdings* (5.7%), *Duke Energy* (5.5%), *Progress Energy* (5.3%), *UIL Holdings* (5.3%), *FirstEnergy* (5.2%), *PPL Corp.* (5.2%), and *SCANA Corp.* (5.1%).

Conclusion

As mentioned earlier, the Value Line Utility Average continues to outperform the Value Line Geometric Average year to date. Due to the weakened economic environment, we believe investors will likely continue to flock to utility stocks in the near term for their relative stability and high dividend yields. That said, it is worth mentioning that the utility industry's positive performance relative to the broader market has raised prices so much that several stocks are not trading within or near their projected 3- to 5-year Target Price Ranges. This often indicates that valuations may be a bit on the high side.

Michael Ratty

Composite Statistics: Electric Utility Industry

2007	2008	2009	2010	2011	2012		14-16
341.6	363.6	321.0	329.2	**320**	**335**	Revenues ($bill)	**385**
27.4	27.7	27.7	30.1	**29.0**	**31.0**	Net Profit ($bill)	**37.0**
33.1%	33.5%	32.2%	34.2%	**34.5%**	**34.5%**	Income Tax Rate	**34.5%**
6.3%	7.8%	9.2%	8.5%	**7.0%**	**7.0%**	AFUDC % to Net Profit	**6.0%**
50.9%	53.6%	52.4%	52.2%	**51.0%**	**50.5%**	Long-Term Debt Ratio	**50.0%**
48.0%	45.4%	46.6%	47.0%	**48.5%**	**49.0%**	Common Equity Ratio	**49.5%**
467.8	514.0	554.1	585.7	**575**	**605**	Total Capital ($bill)	**695**
505.5	554.4	594.5	640.1	**640**	**680**	Net Plant ($bill)	**780**
7.5%	6.9%	6.5%	6.6%	**6.5%**	**6.5%**	Return on Total Cap'l	**7.0%**
11.9%	11.6%	10.5%	10.7%	**10.0%**	**10.0%**	Return on Shr. Equity	**10.5%**
12.1%	11.8%	10.6%	10.8%	**10.0%**	**10.0%**	Return on Com Equity	**10.5%**
5.5%	4.9%	4.2%	4.5%	**4.0%**	**4.0%**	Retained to Com Eq	**4.5%**
55%	58%	61%	59%	**62%**	**61%**	All Div'ds to Net Prof	**58%**
16.9	15.4	12.5	12.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.5**
.90	.93	.83	.82			Relative P/E Ratio	**.90**
3.2%	3.8%	4.8%	4.5%			Avg Ann'l Div'd Yield	**4.3%**

COMPOSITE OPERATING STATISTICS: ELECTRIC UTILITY INDUSTRY

	2008	2009	2010
% Change Retail Sales (kwh)	-1.1	-5.4	+3.6
Average Indust. Use (mwh)	1529	1446	1530
Avg. Indust. Revs. per kwh (¢)	6.66	6.46	6.56
Regulated Cap. at Peak (mw)	NA	NA	NA
Peak Load, Summer (mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr.-end)	+.1	-.2	+1.6
Fixed Charge Coverage (%)	311	280	305

Sources: Annual Reports; Estimates, Value Line; Edison Electric Institute

AMEREN NYSE-AEE

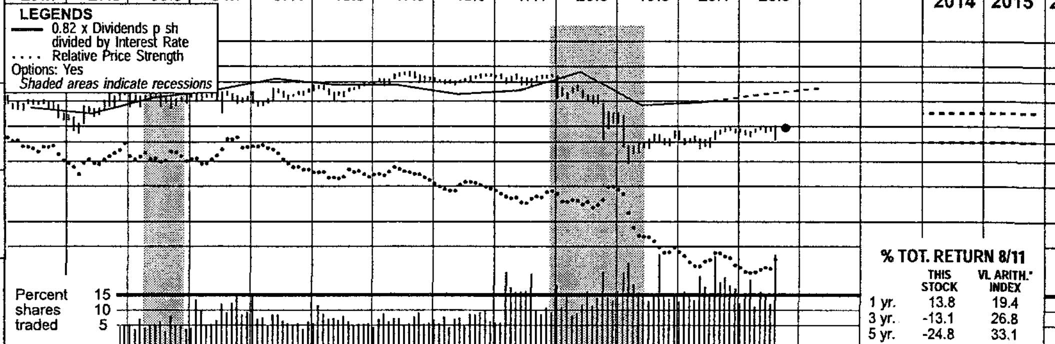
RECENT PRICE **29.46** | P/E RATIO **11.7** (Trailing: 11.4 Median: 15.0) | RELATIVE P/E RATIO **0.87** | DIV'D YLD **5.2%** | VALUE LINE

TIMELINESS 3 Raised 8/27/10
SAFETY 3 Lowered 6/26/09
TECHNICAL 3 Lowered 9/2/11
BETA .80 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	46.9	46.0	45.3	46.5	50.4	56.8	55.2	55.0	54.3	35.3	29.9	30.5
Low:	27.6	36.5	34.7	37.4	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 0.82 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	1	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	179	129	151
to Sell	151	177	152
Hld's(000)	137716	141870	141320

Percent shares traded 15 10 5

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.8	19.4
3 yr.	-13.1	26.8
5 yr.	-24.8	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
20.59	22.13	24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	**31.15**	**31.15**	Revenues per sh	**32.50**
5.14	5.12	4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	**6.00**	**6.10**	"Cash Flow" per sh	**6.50**
2.95	2.86	2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	**2.40**	**2.40**	Earnings per sh A	**2.50**
2.46	2.51	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	**1.54**	**1.54**	Div'd Decl'd per sh B ■ †	**1.54**
3.05	3.18	2.77	2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	**4.80**	**5.25**	Cap'l Spending per sh	**5.75**
22.71	23.06	22.00	22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	**32.65**	**33.45**	Book Value per sh C	**36.00**
102.12	102.12	137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	**244.00**	**247.00**	Common Shs Outst'g D	**256.00**
12.6	13.8	15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	**Bold figures are**	**Value Line estimates**	Avg Ann'l P/E Ratio	**12.5**
.84	.86	.89	.74	.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62			Relative P/E Ratio	**.85**
6.6%	6.3%	6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%			Avg Ann'l Div'd Yield	**5.0%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7396.0 mill. Due in 5 Yrs $1538.0 mill.
LT Debt $7054.0 mill. LT Interest $455.0 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $39.0 mill.
Pension Assets-12/10 $2.72 bill. Oblig. $3.45 bill.
Pfd Stock $142.0 mill. Pfd Div'd $8.0 mill.
807,595 shs. $3.50 to $5.50 cum. (no par), $100 stated value, redeemable at $102.176-$110/sh.; 616,323 shs. 4.00% to 6.625%, $100 par, redeemable at $100-$104/sh.
Common Stock 241,148,657 shs. as of 4/29/11
MARKET CAP: $7.1 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
4505.9	3841.0	4593.0	5160.0	6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	**7600**	**7700**	Revenues ($mill)	**8300**
481.0	393.0	517.0	541.0	628.0	547.0	629.0	615.0	624.0	669.0	**590**	**600**	Net Profit ($mill)	**650**
38.4%	38.9%	36.8%	34.3%	35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	**37.0%**	**37.0%**	Income Tax Rate	**37.0%**
4.3%	2.8%	1.9%	1.8%	2.9%	.7%	.8%	4.6%	5.8%	7.8%	**6.0%**	**6.0%**	AFUDC % to Net Profit	**7.0%**
44.2%	46.0%	47.3%	45.5%	44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	**47.0%**	**46.0%**	Long-Term Debt Ratio	**45.5%**
52.2%	51.4%	50.6%	52.6%	53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	**52.5%**	**53.0%**	Common Equity Ratio	**53.5%**
6419.3	7468.0	8606.0	11036	11932	12063	12654	13712	15991	15185	**15250**	**15650**	Total Capital ($mill)	**17200**
8426.6	8914.0	10917	13297	13572	14286	15069	16567	17610	17853	**18125**	**18525**	Net Plant ($mill)	**19800**
8.7%	6.5%	7.4%	6.0%	6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
13.4%	9.7%	11.4%	9.0%	9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	**7.0%**	**7.0%**	Return on Shr. Equity	**7.0%**
14.0%	9.9%	11.6%	9.1%	9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	**7.0%**	**7.0%**	Return on Com Equity E	**7.0%**
3.6%	.2%	2.2%	.9%	1.7%	.2%	1.3%	1.0%	3.5%	3.8%	**2.5%**	**2.5%**	Retained to Com Eq	**2.5%**
75%	98%	81%	91%	83%	97%	86%	88%	56%	56%	**64%**	**65%**	All Div'ds to Net Prof	**61%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.6	-4.1	+8.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.43	4.45	4.63
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	296	266	293

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.5%	2.5%	*Nil*
"Cash Flow"	1.0%	1.0%	*.5%*
Earnings	-.5%	-1.5%	*-2.0%*
Dividends	-3.0%	-6.0%	*-3.0%*
Book Value	3.5%	2.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2081	1790	2060	1908	7839.0
2009	1916	1684	1815	1675	7090.0
2010	1940	1725	2267	1706	7638.0
2011	1904	1781	***2150***	***1765***	***7600***
2012	***1950***	***1800***	***2150***	***1800***	***7700***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.66	.98	.97	.27	2.88
2009	.66	.77	1.04	.34	2.78
2010	.43	.64	1.49	.21	2.77
2011	.29	.57	***1.24***	***.30***	***2.40***
2012	***.40***	***.60***	***1.10***	***.30***	***2.40***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.635	.635	.635	.635	2.54
2008	.635	.635	.635	.635	2.54
2009	.385	.385	.385	.385	1.54
2010	.385	.385	.385	.385	1.54
2011	.385	.385			

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 811,000 gas customers in Illinois. Electric revenue breakdown: residential, 48%; commercial, 31%; industrial, 10%; other, 11%. Generating sources: coal, 66%; nuclear, 9%; hydro, 2%; gas, 1%; purchased, 22%. Fuel costs: 41% of revenues. '10 reported depreciation rates: 3%-4%. Has 9,800 employees. Chairman, President & CEO: Thomas R. Voss. Incorporated: Missouri. Address: One Ameren Plaza, 1901 Chouteau Avenue, P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren has received an electric rate increase in Missouri. The state commission granted the utility a tariff hike of $173 million, based on a 10.2% return on a 52.2% common-equity ratio. Disappointingly, $89 million of capital investment was disallowed. Ameren has appealed this to the state Court of Appeals. (This will cause a nonrecurring charge, estimated at $0.23 a share, in the third quarter.) New rates took effect at the end of July.

Electric and gas rate requests are pending in Illinois. Ameren is seeking an electric hike of $39 million, based on an 11% return on equity, and a gas increase of $50 million, based on a 10.75% ROE. The requested common-equity ratio is 52.87%. The staff of the Illinois Commerce Commission (ICC) is recommending a total (electric and gas) increase of $31 million, and the state attorney general and Citizens Utility Board are proposing a total *decrease* of $2 million. The ICC's order is due in January, with new rates taking effect shortly thereafter.

Earnings are probably headed down this year. An unusually large number of storms hurt profits in the first half of 2011. Kilowatt-hour sales were running lower than expected, until an unusually hot summer offset this somewhat. Margins are under pressure at Ameren's merchant generation subsidiary, due to weak power prices and rising coal costs. Our 2011 share-net estimate of $2.40 is within Ameren's guidance of $2.30-$2.55.

We look for flat earnings in 2012. We figure that improvement at the utility operations (thanks largely to rate relief) will offset another decline in income at the nonregulated side of the business.

Ameren has announced its strategy for dealing with more stringent EPA rules for coal plants. The company will reduce its capital budget by $700 million by switching to lower-sulfur coal. This will increase its operating expenses, however.

We do not recommend this stock. The dividend is above the utility average, but by less than a percentage point. In our view, this is not enough to compensate investors for a lack of dividend growth potential. With the stock trading near the middle of our 2014-2016 Target Price Range, total return potential is unexciting.

Paul E. Debbas, CFA September 23, 2011

(A) Diluted EPS. Excl. nonrecur. gain (losses): '03, 11¢; '05, (11¢); '10, ($2.19); 3Q '11, *(23¢)*. '09 EPS don't add due to change in shs. Next earnings report due early Nov. (B) Div'ds historically paid in late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $6.98/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '10: 10.1%; in IL in '10: 9.9%-10.3% electric, 9.2%-9.4% gas; earned on avg. com. eq., '10: 8.2%. Regul. Clim.: MO, Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	5
Earnings Predictability	90

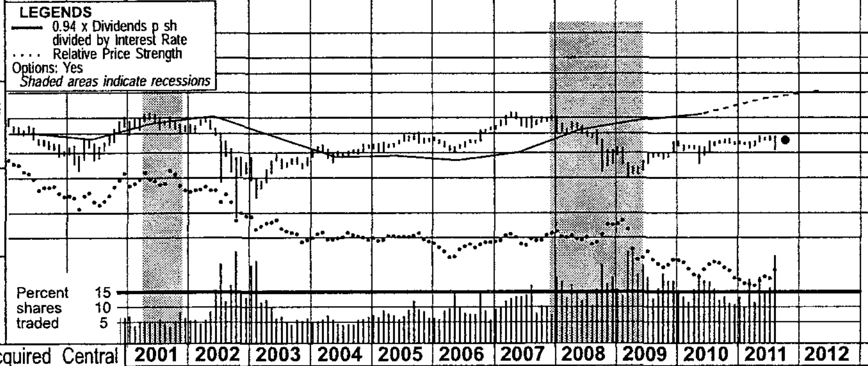
AMERICAN ELEC. PWR. NYSE-AEP

RECENT PRICE **37.13** | P/E RATIO **11.5** (Trailing: 12.0; Median: 13.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **5.1%** | VALUE LINE

TIMELINESS 2 Raised 8/19/11
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Lowered 9/16/11
BETA .70 (1.00 = Market)

High:	48.9	51.2	48.8	31.5	35.5	40.8	43.1	51.2	49.1	36.5	37.9	39.0
Low:	25.9	39.3	15.1	19.0	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1

LEGENDS
— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range
2014 | 2015 | 2016

2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+50%)	*14%*
Low	40	(+10%)	*7%*

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	241	235	236
to Sell	229	236	233
Hld's(000)	316321	315480	318229

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.8	19.4
3 yr.	15.7	26.8
5 yr.	33.0	33.1

American Electric Power acquired Central and South West Corporation (CSW) in 2000. CSW common stockholders received 0.6 of an AEP common share for each of their shares, for a total of $4.5 billion. The transaction was effected under pooling-of-interests accounting rules.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	*31.55*	*33.15*	Revenues per sh	*39.00*
7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	*6.70*	*6.95*	"Cash Flow" per sh	*8.00*
3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	*3.15*	*3.25*	Earnings per sh A	*3.75*
2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	*1.84*	*1.90*	Div'd Decl'd per sh B ■	*2.10*
5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	*5.75*	*6.30*	Cap'l Spending per sh	*7.00*
25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	*29.60*	*31.05*	Book Value per sh C	*36.00*
322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	*485.00*	*489.00*	Common Shs Outst'g D	*500.00*
13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.71	.69	.61	.66	.73	.70	.87	.79	.67	.86	*Value Line*		Relative P/E Ratio	*.85*
5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*
61257	14555	14545	14057	12111	12622	13380	14440	13489	14427	*15300*	*16200*	Revenues ($mill)	*19500*
1063.0	976.0	984.0	1038.0	1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	*1520*	*1590*	Net Profit ($mill)	*1910*
36.0%	25.2%	38.8%	33.1%	29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	--	3.8%	3.6%	5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	*11.0%*	*11.0%*	AFUDC % to Net Profit	*10.0%*
54.6%	56.0%	60.6%	56.2%	54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	*52.0%*	*51.5%*	Long-Term Debt Ratio	*49.5%*
44.6%	43.1%	38.7%	43.1%	44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	*47.5%*	*48.5%*	Common Equity Ratio	*50.5%*
18459	16393	20333	19584	20222	21902	24342	26290	28958	29184	*30150*	*31450*	Total Capital ($mill)	*35800*
24543	21684	22029	22801	24284	26781	29870	32987	34344	35674	*36725*	*38000*	Net Plant ($mill)	*41800*
7.5%	7.5%	6.6%	7.0%	6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
12.7%	13.5%	12.3%	12.1%	11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
12.8%	13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	*10.5%*	*10.5%*	Return on Com Equity E	*10.5%*
3.4%	2.4%	4.5%	5.7%	5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
74%	82%	64%	54%	54%	53%	55%	55%	56%	66%	*59%*	*58%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $18274 mill. **Due in 5 Yrs** $7332 mill.
LT Debt $15564 mill. **LT Interest** $856 mill.
Incl. $1703 mill. securitized bonds.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $306 mill.

Pension Assets-12/10 $3.86 bill. **Oblig.** $4.81 bill.
Pfd Stock $61 mill. **Pfd Div'd** $3 mill.
607,044 shs. 4%-5%, cumulative, callable at $102-$110.

Common Stock 482,273,829 shs.
as of 7/28/11

MARKET CAP: $18 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-.1	-6.4	+4.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.08	4.83	4.95
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	244	265	257

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.5%	-2.0%	*4.0%*
"Cash Flow"	1.0%	2.0%	*3.5%*
Earnings	2.5%	2.0%	*4.5%*
Dividends	-3.5%	2.0%	*4.0%*
Book Value	1.0%	5.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3467	3546	4191	3236	14440
2009	3458	3202	3547	3282	13489
2010	3569	3360	4064	3434	14427
2011	3730	3609	*4311*	*3650*	*15300*
2012	*3900*	*3900*	*4500*	*3900*	*16200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.02	.70	.93	.34	2.99
2009	.89	.68	.93	.49	2.97
2010	.72	.35	1.16	.37	2.60
2011	.83	.73	*1.14*	*.45*	*3.15*
2012	*.90*	*.80*	*1.10*	*.45*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.39	.39	.39	.41	1.58
2008	.41	.41	.41	.41	1.64
2009	.41	.41	.41	.41	1.64
2010	.41	.42	.42	.46	1.71
2011	.46	.46	.46		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.3 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 37%; commercial, 25%; industrial, 21%; wholesale, 14%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 35% of revenues. '10 deprec. rate: 3.3%. Has 18,700 employees. Chairman & CEO: Michael G. Morris. President: Nicholas K. Akins. Inc.: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power is facing significant upgrades and asset retirements stemming from new EPA rules affecting coal-fired generating plants. In early June, AEP announced its expected compliance plan, which called for spending $6 billion-$8 billion through the end of the decade. The company would upgrade some plants, retire nearly 6,000 megawatts of capacity, convert 1,070 mw of coal-fired units to use gas, and construct 1,220 mw of gas-fired generation. Most of these expenditures would be recoverable in customers' rates, depending upon what happens in Ohio (see below). AEP won't finalize its plans until after the EPA issues a rule in November dealing with mercury emissions. Until the company's plans are set, our capital spending estimates and projections won't reflect the new spending.

AEP has reached a regulatory settlement for generation in Ohio. The agreement, which has some opposition and must still be approved by the Public Utilities Commission, calls for a gradual transition to market prices by 2015, with AEP's generating plants being transferred to a nonutility subsidiary. This should mitigate the adverse effects of customer choice of energy suppliers, which is hurting owners of generating plants in Ohio.

Earnings should advance significantly in 2011, followed by a much smaller increase in 2012. The June-quarter comparison was easy because the cost of a restructuring program lowered share net by $0.39 in 2010. Ongoing rate relief is another plus for the bottom line. We raised our 2011 profit estimate by $0.05 a share due to an unusually hot summer. Our revised estimate remains within AEP's earnings target of $3.00-$3.20 a share. Our 2012 forecast is still $3.25 a share.

AEP is expecting a sizable payment in Texas. A state Supreme Court ruling will enable the company to recoup $420 million that was denied by the state commission in 2006. With interest, the payment might be more than double this amount. AEP plans to use the cash for debt retirement and capital spending.

This timely stock has some appeal for utility investors. The yield is above the mean for electric companies, as is its 3- to 5-year total return potential.

Paul E. Debbas, CFA *September 23, 2011*

(A) Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); 'll, (10¢); gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '09, (1¢). '09 EPS don't add due to change in shs. Next egs. due late Oct. (B) Div'ds historically paid early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '10: $16.31/sh. (D) In mill. (E) Rate base: various. Rates allowed on com. eq.: 9.96%-15.7%; earned on avg. com. eq., '10: 9.3%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	90

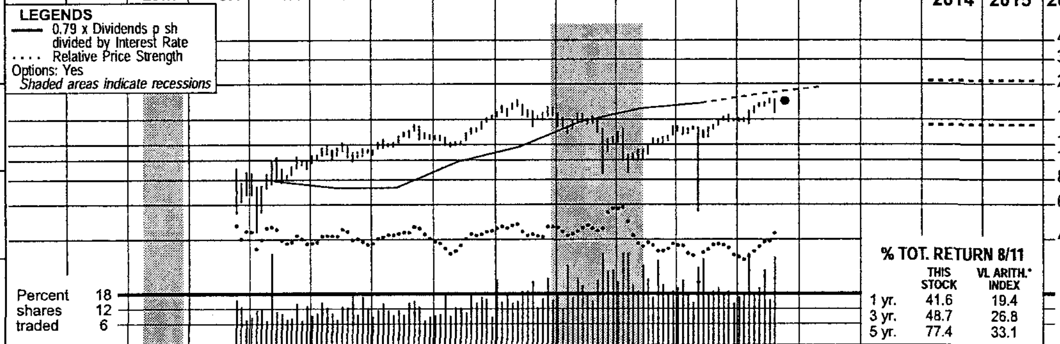
CENTERPOINT EN'RGY NYSE-CNP

RECENT PRICE	19.83	P/E RATIO	16.9 (Trailing: 16.4; Median: NMF)	RELATIVE P/E RATIO	1.26	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 2 Raised 5/13/11
SAFETY 3 Raised 3/31/06
TECHNICAL 2 Raised 9/9/11
BETA .80 (1.00 = Market)

High:	9.2	10.5	12.3	15.1	16.9	20.2	17.3	14.9	17.0	20.4
Low:	5.4	4.4	9.7	10.5	11.6	14.7	8.5	8.7	5.5	15.1

Target Price Range
2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+25%)	9%
Low	15	(-25%)	-2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	1	0	0	0
Options	0	2	0	0	0	1	0	2	0
to Sell	0	3	0	0	0	1	0	3	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	168	151	174
to Sell	159	174	165
Hld's(000)	293850	297873	297292

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.6	19.4
3 yr.	48.7	26.8
5 yr.	77.4	33.1

CenterPoint Energy owns the utility operations that were part of Reliant Energy. The stock began trading on the New York Stock Exchange on Oct. 1, 2002, a day after Reliant Energy spun off its 83% interest in Reliant Resources, which has been renamed RRI Energy (NYSE: RRI). On Jan. 6, 2003, CenterPoint completed the distribution to its shareholders of a 19% interest in Texas Genco Holdings, which owns generating assets in Texas. CenterPoint reacquired the publicly traded stock on Dec. 14, 2004 as the first step of a sale of Texas Genco.

2001A	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
35.18	26.40	31.87	27.63	31.33	29.71	29.82	32.71	21.14	20.69	*19.70*	*19.65*	Revenues per sh	*21.75*
3.69	3.34	3.98	2.56	2.72	3.47	3.39	3.42	2.94	3.14	*3.45*	*3.60*	"Cash Flow" per sh	*4.25*
1.54	1.29	1.37	.61	.67	1.33	1.17	1.30	1.01	1.07	*1.20*	*1.20*	Earnings per sh B	*1.35*
1.50	1.07	.40	.40	.40	.60	.68	.73	.76	.78	*.79*	*.80*	Div'd Decl'd per sh C ■ †	*.90*
6.78	2.85	2.11	1.72	2.23	3.21	3.45	2.95	2.96	3.55	*3.15*	*2.45*	Cap'l Spending per sh	*2.00*
22.24	4.74	5.75	3.59	4.18	4.96	5.61	5.89	6.74	7.53	*9.90*	*10.35*	Book Value per sh D	*12.00*
302.94	300.10	306.30	308.05	310.33	313.65	322.72	346.09	391.75	424.70	*426.00*	*427.00*	Common Shs Outst'g E	*430.00*
--	5.6	6.0	17.8	19.1	10.3	15.0	11.3	11.8	13.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
--	.31	.34	.94	1.02	.56	.80	.68	.79	.88	*Value Line*		Relative P/E Ratio	*.95*
--	14.8%	4.8%	3.7%	3.1%	4.4%	3.9%	5.0%	6.4%	5.3%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
10656	7922.5	9760.1	8510.4	9722.0	9319.0	9623.0	11322	8281.0	8785.0	*8400*	*8400*	Revenues ($mill)	*9350*
446.9	386.3	419.7	205.7	225.0	432.0	399.0	447.0	372.0	442.0	*515*	*520*	Net Profit ($mill)	*600*
33.8%	35.0%	32.5%	40.2%	40.5%	12.6%	32.8%	38.3%	32.1%	37.3%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
2.0%	3.1%	3.1%	1.9%	1.8%	2.3%	5.5%	2.7%	1.3%	2.7%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
45.5%	87.4%	86.0%	86.7%	86.9%	83.4%	82.2%	83.3%	77.6%	73.8%	*72.0%*	*68.5%*	Long-Term Debt Ratio	*68.5%*
54.5%	12.6%	14.0%	13.3%	13.1%	16.6%	17.8%	16.7%	22.4%	26.2%	*28.0%*	*31.5%*	Common Equity Ratio	*31.5%*
12363	11322	12544	8298.5	9864.0	9358.0	10174	12218	11758	12199	*15025*	*14075*	Total Capital ($mill)	*16200*
11200	11409	11812	8186.4	8492.0	9204.0	9740.0	10296	10788	11732	*12175*	*12250*	Net Plant ($mill)	*11900*
5.2%	6.6%	6.5%	6.8%	5.3%	7.8%	6.9%	6.0%	5.8%	6.1%	*5.5%*	*6.0%*	Return on Total Cap'l	*5.5%*
6.6%	27.2%	23.8%	18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	*12.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
6.6%	27.2%	23.8%	18.6%	17.4%	27.8%	22.0%	21.9%	14.1%	13.8%	*12.0%*	*12.0%*	Return on Com Equity F	*11.5%*
.2%	4.3%	16.0%	7.5%	7.8%	15.7%	10.0%	9.9%	3.6%	3.8%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
97%	84%	33%	60%	55%	43%	55%	55%	74%	72%	*66%*	*66%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $9087.0 mill. **Due in 5 Yrs** $4154.0 mill.
LT Debt $8510.0 mill. **LT Interest** $511.0 mill.
Incl. $2371.0 mill. transition & system restoration bonds.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $15.0 mill.
Pension Assets-12/10 $1.50 bill. **Oblig.** $1.97 bill.
Pfd Stock None
Common Stock 425,856,294 shs. as of 7/15/11
MARKET CAP: $8.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.9	-.3	+3.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+1.5	+1.4	+1.3
Fixed Charge Cov. (%)	207	173	197

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	-4.0%	*-2.0%*
"Cash Flow"	--	.5%	*5.0%*
Earnings	--	5.0%	*3.0%*
Dividends	--	13.5%	*3.0%*
Book Value	--	8.5%	*10.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2008	3363	2670	2515	2774	11322
2009	2766	1640	1576	2299	8281.0
2010	3023	1756	1908	2098	8785.0
2011	2587	1837	*1976*	*2000*	*8400*
2012	*2700*	*1750*	*1850*	*2100*	*8400*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2008	.36	.30	.39	.25	1.30
2009	.19	.24	.31	.27	1.01
2010	.29	.20	.29	.29	1.07
2011	.35	.28	*.29*	*.28*	*1.20*
2012	*.32*	*.26*	*.31*	*.31*	*1.20*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.17	.17	.17	.17	.68
2008	.1825	.1825	.1825	.1825	.73
2009	.19	.19	.19	.19	.76
2010	.195	.195	.195	.195	.78
2011	.1975	.1975	.1975		

BUSINESS: CenterPoint Energy, Inc. is a holding company for Houston Electric, which serves 2.1 million customers in Houston and environs, and gas utilities with 3.3 million customers: Entex (Texas, Louisiana, Mississippi); Arkla (Arkansas, Louisiana, Oklahoma, Texas); and Minnegasco (Minnesota). Has gas pipeline and storage assets. Discont. Texas Genco Holdings in '04. Electric rev. breakdown: residential, 52%; commercial, 31%; industrial, 15%; other, 2%. Does not own generating assets. Natural gas costs: 52% of revs. '10 deprec. rate: 5.6%. Has 8,800 employees. Chairman: Milton Carroll. President & CEO: David M. McClanahan. Inc.: TX. Address: 1111 Louisiana, P.O. Box 4567, Houston, TX 77210-4567. Tel.: 713-207-1111. Internet: www.centerpointenergy.com.

CenterPoint Energy is awaiting the resolution of a long-running regulatory matter. This dates back to a $947 million aftertax charge that the company took in 2004, after the Public Utility Commission of Texas (PUCT) disallowed some costs associated with the utility's generating assets. CenterPoint appealed the order and was ultimately successful. The state Supreme Court remanded the case back to the PUCT so that CenterPoint could recoup the monies that were disallowed, plus interest. The utility will ask the PUCT for permission to recover the money through the issuance of securitized bonds. CenterPoint and various intervenors are arguing over what is recoverable, but the company will wind up with a large sum of money—roughly $1.1 billion after taxes, if it prevails. CenterPoint's priority is to use the cash to expand its business through capital investments or acquisitions. Debt retirement and a stock buyback are likely, too. It appears as if this matter will not be resolved until October, at the earliest.

We have raised our 2011 earnings estimate by $0.05 a share, to $1.20. Second-quarter profits were above our expectation, due in part to warmer-than-normal weather patterns. Our 2012 forecast is based on normal weather. One factor that will hurt results is a negative electric rate ruling, which CenterPoint has appealed to the state district court, that took effect at the start of September. The order will reduce operating income by $10 million this year and $30 million annually.

CenterPoint is looking to expand its Field Services operation. This division is benefiting from projects that went into service in the past year. Its operating income rose 39% in the first half of 2011.

This timely stock has been one of the top-performing utility issues so far this year, having risen 26% to date. This is largely due to investors' enthusiasm about the favorable verdict from the Texas Supreme Court. We believe there is also some takeover speculation reflected in the share price. Following the stock's run-up, the dividend yield is not exceptional for a utility, and with the quotation now in the middle of our 2014-2016 Target Price Range, total return potential over that time frame is low.

Paul E. Debbas, CFA *September 23, 2011*

(A) Pro forma data. (B) Diluted EPS. Excl. extraordinary gains (loss): '04, ($2.72); '05, 9¢; '11, *$1.94*; gain (losses) on discont. ops.: '03, 2¢; '04, (37¢); '05, (1¢). Next earnings report due early Nov. (C) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (D) Incl. intangibles. In '10: $12.10/sh. (E) In mill. (F) Rate base: Net orig. cost. Rate allowed on com. eq. (elec.) in '11: 10%; (gas): 9.45%-11.25%; earned on avg. com. eq., '10: 15.1%. Regulatory Climate: Average.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	65

CLECO CORPORATION NYSE-CNL

RECENT PRICE	34.63	P/E RATIO	14.9 (Trailing: 16.0 / Median: 14.0)	RELATIVE P/E RATIO	1.11	DIV'D YLD	3.4%	VALUE LINE

TIMELINESS **3** Lowered 2/11/11

SAFETY **2** Raised 6/24/11

TECHNICAL **3** Raised 6/10/11

BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	28.3	27.3	24.9	18.4	20.8	24.4	26.2	29.8	28.4	28.1	31.8	36.1
Low:	15.1	19.2	9.7	11.0	16.2	18.9	20.5	22.1	17.3	18.7	24.3	30.1

Target Price Range 2014 | 2015 | 2016

2014-16 PROJECTIONS

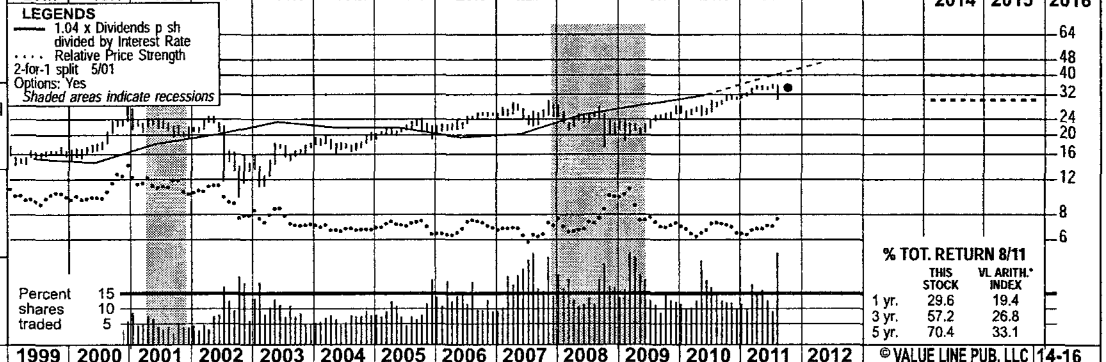
	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	2	0	0	0
Options	0	4	0	0	0	2	0	0	1
to Sell	0	4	0	0	0	3	0	2	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	79	85	73
to Sell	79	80	94
Hld's(000)	44280	44515	44773



% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.6	19.4
3 yr.	57.2	26.8
5 yr.	70.4	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
8.79	9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	*19.30*	*19.75*	Revenues per sh	*22.25*
1.99	2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	*5.65*	*5.80*	"Cash Flow" per sh	*6.50*
1.04	1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	*2.40*	*2.40*	Earnings per sh A	*2.75*
.75	.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	*1.09*	*1.22*	Div'd Decl'd per sh B ■ †	*1.60*
1.29	1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	*4.15*	*3.60*	Cap'l Spending per sh	*4.00*
7.91	8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	*23.65*	*24.90*	Book Value per sh C	*28.50*
44.85	44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	*60.70*	*60.70*	Common Shs Outst'g D	*60.70*
11.6	11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.78	.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.79	*Value Line*		Relative P/E Ratio	*.85*
6.2%	5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	*estimates*		Avg Ann'l Div'd Yield	*4.6%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1400.0 mill. Due in 5 Yrs $230.2 mill.
LT Debt $1387.3 mill. LT Interest $84.6 mill.
Incl. $17.5 million capitalized leases.
(LT interest earned: 3.7x)

Leases, Uncapitalized Annual rentals $9.2 mill.
Pension Assets-12/10 $242.5 mill. Oblig. $330.3 mill.

Pfd Stock None

Common Stock 61,062,449 shs.
as of 7/29/11
MARKET CAP: $2.1 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
1058.6	721.2	874.6	745.8	920.2	1000.7	1030.6	1080.2	853.8	1148.7	*1170*	*1200*	Revenues ($mill)	*1350*
72.3	74.2	61.2	66.1	75.0	74.7	79.6	102.1	106.3	139.5	*145*	*150*	Net Profit ($mill)	*170*
34.7%	36.9%	37.2%	35.2%	39.2%	36.0%	24.3%	15.3%	8.3%	44.1%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
16.7%	12.6%	5.8%	7.5%	4.3%	14.2%	57.9%	82.8%	93.5%	12.2%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*3.0%*
55.2%	60.0%	64.4%	44.5%	46.3%	40.9%	43.2%	51.1%	54.2%	51.5%	*46.5%*	*45.5%*	Long-Term Debt Ratio	*42.0%*
42.4%	38.2%	33.8%	53.1%	52.0%	57.8%	56.7%	48.9%	45.8%	48.5%	*53.5%*	*54.5%*	Common Equity Ratio	*58.0%*
1134.7	1448.7	1408.5	1011.6	1315.9	1515.6	1780.5	2167.7	2436.4	2717.9	*2685*	*2760*	Total Capital ($mill)	*2975*
1224.7	1566.2	1417.1	1060.0	1188.7	1304.9	1725.9	2045.3	2247.0	2784.2	*2840*	*2855*	Net Plant ($mill)	*2875*
8.6%	7.1%	6.7%	8.9%	7.1%	6.3%	5.6%	6.1%	5.9%	6.6%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
14.2%	12.8%	12.2%	11.8%	10.6%	8.3%	7.9%	9.6%	9.5%	10.6%	*10.0%*	*10.0%*	Return on Shr. Equity	*9.5%*
14.6%	13.1%	12.5%	11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	10.6%	*10.0%*	*10.0%*	Return on Com Equity E	*9.5%*
6.5%	5.6%	3.5%	3.9%	4.1%	3.0%	2.6%	4.5%	4.7%	6.1%	*5.5%*	*5.0%*	Retained to Com Eq	*4.0%*
57%	58%	72%	68%	62%	65%	68%	53%	51%	42%	*45%*	*50%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.1	-6.0	+5.9
Avg. Indust. Use (MWH)	4535	3532	3657
Avg. Indust. Revs. per KWH (¢)	7.89	6.48	7.68
Capacity at Peak (Mw)	2254	2355	NA
Peak Load, Summer (Mw)	2113	2242	2348
Annual Load Factor (%)	57.0	53.5	55.8
% Change Customers (avg.)	+.9	+.7	+.7
Fixed Charge Cov. (%)	159	138	294

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 279,000 customers in central Louisiana. Through a subsidiary, has 775 megawatts of wholesale capacity. Electric revenue breakdown: residential, 45%; commercial, 27%; industrial, 14%; other, 14%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: gas & oil, 30%; coal & lignite, 29%; petroleum coke, 16%; purchased, 25%. Fuel costs: 44% of revenues. '10 reported deprec. rate (utility): 2.6%. Has 1,300 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Inc.: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, LA 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	1.0%	-.5%	*4.5%*
"Cash Flow"	5.5%	8.5%	*7.5%*
Earnings	4.5%	7.5%	*6.0%*
Dividends	1.0%	.5%	*9.5%*
Book Value	7.5%	11.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	222.5	274.8	343.7	239.2	1080.2
2009	213.0	207.2	241.5	192.1	853.8
2010	272.3	275.9	343.9	256.6	1148.7
2011	253.7	272.9	*370*	*273.4*	*1170*
2012	*270*	*280*	*370*	*280*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.37	.49	.62	.22	1.70
2009	.11	.45	.99	.21	1.76
2010	.56	.58	.82	.33	2.29
2011	.48	.52	*1.10*	*.30*	*2.40*
2012	*.40*	*.60*	*1.10*	*.30*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.225	.225	.225	.225	.90
2008	.225	.225	.225	.225	.90
2009	.225	.225	.225	.225	.90
2010	.225	.25	.25	.25	.98
2011	.25	.28	.28		

We estimate that Cleco Corporation's earnings will rise at a mid-single-digit pace in 2011. Cleco Power, the company's regulated utility subsidiary, is benefiting from a regulatory plan that allows it a return on equity of 11.7%, with a chance to earn up to a 12.3% ROE, thanks to incentive ratemaking. We have raised our 2011 earnings estimate by $0.05 a share, to $2.40, due to hotter-than-usual summer weather conditions. That's the upper end of management's targeted range of $2.30-$2.40 a share, which was based on normal weather. **We now look for flat earnings in 2012,** based on our assumption of a return to normal weather patterns.

Dividend growth potential is high. After several years in which the board of directors did not raise the disbursement, it lifted the payout in 2010. Earlier this year, the board boosted the quarterly dividend by $0.03 a share (12%), and Cleco has already stated that an increase of $0.03125 a share (11.1%) is in the offing for 2012.

The company completed an asset sale in the second quarter. Cleco sold its 50% stake in Acadia Unit 2, a gas-fired plant, for $150 million. It used the proceeds for debt reduction. The company recorded a gain of $0.63 a share on the sale, which we excluded from our presentation as a nonrecurring item.

Cleco is still deciding what to do with the Coughlin plant. This 775-megawatt gas-fired facility is the company's sole remaining nonregulated generating asset. Its capacity will be available at the start of 2012, after a contract expires. New EPA rules that will increase costs for coal-fired units might well make Coughlin a more valuable asset.

Two capital projects are under way. Cleco has a 50% stake in a $250 million transmission project. This should be complete by the summer of 2012. The utility is spending $73 million (including a $20 million grant from the federal government) on an advanced metering system. This should be finished by 2013.

This stock does not stand out for the short or long term. The yield is about a percentage point below the utility mean, and 3- to 5-year total return potential is unexciting, despite the good dividend growth prospects mentioned above.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; 2Q '11, 63¢; losses from disc. ops.: '00, 14¢; '01, 4¢. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '10: $10.51/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09: 11.7%; earned on avg. com. eq., '10: 11.9%. Regul. Climate: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	75

CMS ENERGY CORP. NYSE-CMS

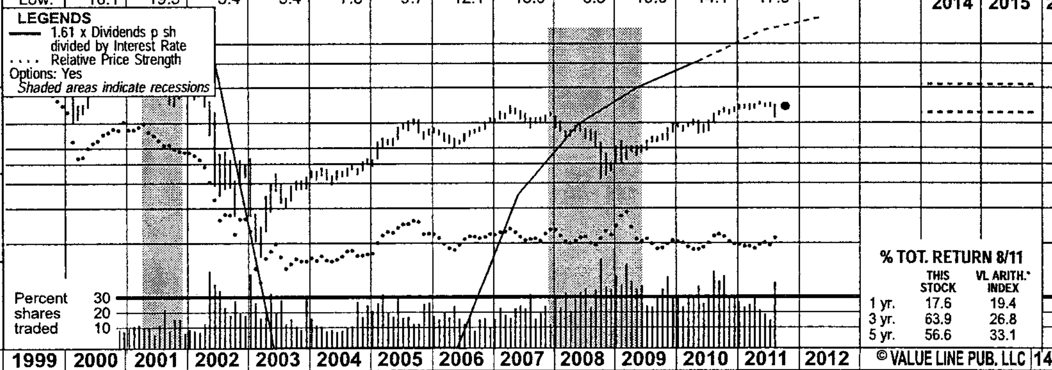
RECENT PRICE	19.39	P/E RATIO	13.5 (Trailing: 12.8 / Median: 17.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	4.6%	VALUE LINE

TIMELINESS 3 Lowered 8/12/11
SAFETY 3 Raised 12/29/06
TECHNICAL 3 Lowered 9/16/11
BETA .75 (1.00 = Market)

High:	32.3	31.8	24.8	10.7	10.6	16.8	17.0	19.5	17.5	16.1	19.3	20.5	
Low:	16.1	19.5	5.4	3.4	7.8	9.7	12.1	15.0	8.3	10.0	14.1	17.0	

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 1.61 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+30%)	11%
Low	18	(-5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	0
to Sell	0	1	0	0	0	1	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	147	142	162
to Sell	153	149	132
Hld's(000)	233569	236444	236182

Percent shares traded 30 / 20 / 10

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	19.4
3 yr.	63.9	26.8
5 yr.	56.6	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
42.47	45.70	47.49	47.56	52.59	74.24	72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	26.20	27.15	Revenues per sh	30.00
6.77	7.18	7.39	6.60	7.87	7.61	5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.70	3.85	"Cash Flow" per sh	4.50
2.27	2.45	2.61	2.24	2.85	2.53	1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.55	Earnings per sh A	1.75
.90	1.02	1.14	1.26	1.39	1.46	1.46	1.09	--	--	--	--	.20	.36	.50	.66	.84	.92	Div'd Decl'd per sh B ■	1.10
5.84	6.95	7.05	11.98	9.69	8.51	9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	4.25	5.10	Cap'l Spending per sh	4.75
16.04	17.95	19.61	20.63	21.17	19.48	14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	12.00	12.70	Book Value per sh C	15.00
91.59	94.81	100.79	108.11	116.04	121.20	132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	252.00	254.00	Common Shs Outst'g D	260.00
11.0	12.5	13.5	19.9	13.9	9.6	20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	Bold figures are		Avg Ann'l P/E Ratio	13.0
.74	.78	.78	1.03	.79	.62	1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	Value Line		Relative P/E Ratio	.85
3.6%	3.3%	3.2%	2.8%	3.5%	6.0%	5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%	estimates		Avg Ann'l Div'd Yield	4.9%

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7484.0 mill. Due in 5 Yrs $2745.0 mill.
LT Debt $6361.0 mill. LT Interest $356.0 mill.
Incl. $177.0 mill. capitalized leases.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $29.0 mill.
Pension Assets-12/10 $1.40 bill. Oblig. $1.90 bill.
Pfd Stock $44.0 mill. **Pfd Div'd** $2.0 mill.
Incl. 441,599 shs. $4.16-$4.50 $100 par, cum., callable at $103.25-$110.
Common Stock 251,800,000 shs.

MARKET CAP: $4.9 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
9597.0	8687.0	5513.0	5472.0	6288.0	6810.0	6519.0	6821.0	6205.0	6432.0	6600	6900	Revenues ($mill)	7800
169.0	d414.0	d40.0	144.0	247.0	158.0	168.0	300.0	231.0	356.0	380	415	Net Profit ($mill)	480
29.8%	--	NMF	18.6%	25.6%	--	37.6%	31.6%	34.6%	38.1%	38.0%	38.0%	Income Tax Rate	38.0%
22.5%	--	--	--	15.4%	6.3%	3.6%	1.3%	13.0%	2.2%	8.0%	13.0%	AFUDC % to Net Profit	12.0%
80.9%	84.4%	78.2%	75.3%	73.5%	71.7%	70.5%	69.4%	67.9%	70.1%	69.0%	68.5%	Long-Term Debt Ratio	64.0%
18.7%	15.0%	18.3%	21.5%	23.4%	24.9%	25.9%	27.4%	29.0%	29.5%	30.5%	31.0%	Common Equity Ratio	35.5%
10131	7532.0	8652.0	9640.0	9913.0	8961.0	8212.0	8993.0	8977.0	9473.0	9925	10325	Total Capital ($mill)	11000
8362.0	5234.0	6944.0	8636.0	7845.0	7976.0	8728.0	9190.0	9682.0	10069	10600	11325	Net Plant ($mill)	13500
5.0%	NMF	2.7%	4.4%	5.0%	4.5%	4.5%	5.4%	4.7%	5.8%	6.0%	6.0%	Return on Total Cap'l	6.5%
8.7%	NMF	NMF	6.1%	9.4%	6.2%	6.9%	10.9%	8.0%	12.5%	12.5%	12.5%	Return on Shr. Equity	12.5%
8.8%	NMF	NMF	6.2%	9.9%	6.4%	7.2%	11.7%	8.5%	12.5%	12.5%	12.5%	Return on Com Equity E	12.5%
NMF	NMF	NMF	6.2%	9.9%	6.4%	5.1%	8.4%	4.1%	6.9%	5.5%	5.5%	Retained to Com Eq	5.0%
113%	NMF	NMF	11%	6%	10%	35%	31%	54%	46%	56%	57%	All Div'ds to Net Prof	59%

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-3.5	-4.6	+5.4
Avg. Indust. Use (MWH)	1234	1076	1027
Avg. Indust. Revs. per KWH (¢)	7.67	7.29	8.27
Capacity at Peak (Mw)	9586	8954	9246
Peak Load, Summer (Mw)	7488	7421	8190
Annual Load Factor (%)	59.2	55.9	55.3
% Change Customers (yr-end)	+.4	-.9	+.2
Fixed Charge Cov. (%)	190	159	215

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-7.0%	-1.5%	1.5%
"Cash Flow"	-6.5%	5.0%	3.5%
Earnings	-7.5%	17.5%	7.0%
Dividends	-9.5%	--	14.0%
Book Value	-6.0%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2184	1365	1428	1844	6821.0
2009	2104	1225	1263	1613	6205.0
2010	1967	1340	1443	1682	6432.0
2011	2055	1364	1431	1745	6600
2012	2175	1450	1500	1775	6900

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.44	.20	.33	.27	1.23
2009	.31	.28	.29	.05	.93
2010	.35	.26	.53	.21	1.33
2011	.51	.26	.41	.27	1.45
2012	.50	.32	.43	.30	1.55

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.05	.05	.05	.05	.20
2008	.09	.09	.09	.09	.36
2009	.125	.125	.125	.125	.50
2010	.15	.15	.15	.21	.66
2011	.21	.21	.21		

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,166 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 42%; commercial, 31%; industrial, 20%; other, 7%. Generating sources: coal, 48%; gas, 3%; hydro, 1%; purchased, 48%. Fuel costs: 55% of revenues. '10 reported deprec. rates: 3.0% electric, 2.9% gas, 7.4% other. Has 7,800 employees. Chairman: David W. Joos. President & CEO: John G. Russell. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

CMS Energy's utility subsidiary has electric and gas rate cases pending. Consumers Energy has filed for an electric rate hike of $195 million (5.4%), based on a 10.7% return on a 42.07% common-equity ratio. Under Michigan regulatory law, the utility will self-implement an increase in December. A rate order is due the following June. Consumers is seeking a gas tariff increase of $49 million, based on a 10.7% return on a 41.55% common-equity ratio. The utility will self-implement an increase in March. The rate order is due in September.

The unusually hot weather that the service area experienced this summer will have just a small effect on the company's profits. That's because the utility operates under a mechanism that decouples electric revenues and electric volume. Weather can still affect the bottom line, however. Greater-than-usual storm activity hurt profits by $0.07 a share in the first half of 2011, and Consumers still has sensitivity to weather in the gas side of its business.

We are sticking with our earnings estimates for 2011 and 2012. Our profit estimate of $1.45 a share for this year excludes a $0.12 noncash state income tax benefit that CMS booked in the second quarter. We are treating this gain as a nonrecurring item. (The company's earnings target for 2011 is $1.44 a share.) Our 2012 forecast of $1.55 a share assumes reasonable regulatory treatment. The company has set a target for average annual earnings growth of 5%-7%.

Consumers is building its first wind project. This will provide 100 megawatts of capacity. The $232 million project is expected to be on line by the end of 2012. It will help the utility meet the state's renewable energy requirement.

Financing needs are small. CMS expects to benefit from tax-loss carryforwards in the next few years. No large equity offerings are planned, but the company intends to raise $25 million-$30 million of common equity annually through various stock plans.

This stock's dividend yield and 3- to 5-year total return potential are roughly equivalent to the norms for the electric utility industry.

Paul E. Debbas, CFA *September 23, 2011*

(A) Dil. EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢). '08 EPS don't add due to rounding, '10 due to change in shs. Next egs. report due early Nov. (B) Div'ds historically paid late Feb., May, Aug. & Nov. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $8.39/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in '10: 10.7% elec.; in '10: 10.55% gas; earn. on avg. com. eq., '10: 12.6%. Regul. Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	35

CONSTELLATION EGY. NYSE-CEG

RECENT PRICE	37.08	P/E RATIO	13.7 (Trailing: 32.2 Median: 16.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	2.6%	VALUE LINE

TIMELINESS – Suspended 5/6/11

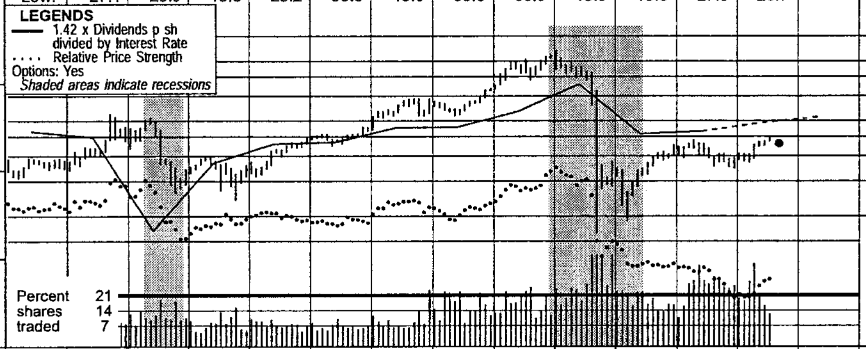
SAFETY 3 New 12/26/08

TECHNICAL – Suspended 5/6/11

BETA .80 (1.00 = Market)

High:	52.1	50.1	32.4	39.6	44.9	62.6	70.2	104.3	108.0	36.6	38.7	40.2
Low:	27.1	20.9	19.3	25.2	35.9	43.0	50.6	68.8	13.0	15.0	27.6	29.7

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+35%)	10%
Low	30	(-20%)	-2%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	158	146	134
to Sell	176	180	178
Hld's(000)	140662	139145	142927

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.7	21.2
3 yr.	-48.0	42.7
5 yr.	-22.1	48.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
19.89	21.35	22.40	22.50	25.32	25.77	24.00	28.53	57.82	71.17	96.08	106.83	118.77	99.53	77.61	71.78	*72.50*	*69.30*	Revenues per sh	*78.00*
4.59	4.45	4.66	4.93	5.57	5.78	5.02	5.50	6.31	6.89	6.78	6.81	7.52	3.36	5.29	4.37	*5.20*	*5.30*	"Cash Flow" per sh	*7.00*
2.02	1.85	1.97	2.06	2.18	2.30	2.20	2.29	2.76	3.19	3.38	3.76	4.29	.48	1.79	1.61	*2.30*	*2.30*	Earnings per sh A	*3.50*
1.55	1.59	1.63	1.67	1.68	1.68	.48	.96	1.04	1.14	1.34	1.51	1.74	1.91	.96	.96	*.96*	*.96*	Div'd Decl'd per sh B ■	*1.00*
2.48	2.44	2.53	2.27	2.92	7.17	8.05	5.05	3.92	3.99	4.26	5.33	7.26	9.71	7.61	4.98	*4.20*	*5.00*	Cap'l Spending per sh	*6.75*
19.07	19.35	19.44	19.98	20.01	20.95	23.48	23.43	24.67	26.81	27.57	25.53	29.93	15.98	43.27	39.19	*40.40*	*41.65*	Book Value per sh C	*48.00*
147.53	147.67	147.67	149.25	149.56	150.53	163.71	164.84	167.82	176.33	178.30	180.52	178.44	199.13	200.99	199.79	*201.00*	*202.00*	Common Shs Outst'g D	*205.00*
12.4	14.7	14.0	15.3	13.2	15.8	16.4	12.1	11.8	12.5	16.0	15.6	20.5	NMF	15.5	20.5	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	*11.5*
.83	.92	.81	.80	.75	1.03	.84	.66	.67	.66	.85	.84	1.09	NMF	1.03	1.31			Relative P/E Ratio	*.75*
6.2%	5.9%	5.9%	5.3%	5.8%	4.6%	1.3%	3.5%	3.2%	2.9%	2.5%	2.6%	2.0%	2.9%	3.5%	2.9%			Avg Ann'l Div'd Yield	*2.5%*
						3928.3	4703.0	9703.0	12550	17132	19285	21193	19818	15599	14340	*14500*	*14000*	Revenues ($mill)	*16000*
						366.3	372.1	472.2	567.8	619.9	696.8	796.4	99.2	372.4	336.3	*480*	*480*	Net Profit ($mill)	*760*
						34.6%	40.3%	35.6%	27.1%	24.8%	31.0%	33.7%	65.4%	17.6%	35.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						15.7%	11.8%	2.9%	1.9%	1.6%	2.0%	2.4%	50.4%	23.4%	9.8%	*2.0%*	*3.0%*	AFUDC % to Net Profit	*4.0%*
						40.2%	53.2%	53.8%	49.5%	46.1%	46.8%	45.7%	60.2%	35.1%	35.7%	*30.5%*	*32.5%*	Long-Term Debt Ratio	*31.5%*
						57.0%	44.6%	44.2%	48.6%	51.9%	51.1%	52.4%	37.6%	63.5%	62.8%	*68.0%*	*66.0%*	Common Equity Ratio	*67.0%*
						6746.1	8666.2	9369.7	9730.1	9474.8	9021.6	10191	8470.1	13701	12468	*11925*	*12750*	Total Capital ($mill)	*14700*
						7700.4	7957.1	9601.5	10087	10067	9222.1	9767.1	10717	8453.8	9278.8	*9550*	*9950*	Net Plant ($mill)	*11900*
						6.5%	5.9%	6.7%	7.4%	8.0%	9.3%	9.1%	3.2%	4.0%	3.6%	*5.0%*	*4.5%*	Return on Total Cap'l	*6.0%*
						9.1%	9.2%	10.9%	11.5%	12.1%	14.5%	14.4%	2.9%	4.2%	4.2%	*6.0%*	*5.5%*	Return on Shr. Equity	*7.5%*
						9.2%	9.3%	11.1%	11.7%	12.3%	14.8%	14.7%	2.7%	4.1%	4.1%	*6.0%*	*5.5%*	Return on Com Equity E	*7.5%*
						6.0%	5.7%	7.0%	7.7%	7.7%	9.1%	8.9%	NMF	1.5%	1.8%	*3.5%*	*3.5%*	Retained to Com Eq	*5.5%*
						37%	41%	39%	36%	39%	40%	40%	NMF	65%	58%	*43%*	*43%*	All Div'ds to Net Prof	*29%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $4557.9 mill. **Due in 5 Yrs** $1515.7 mill.
LT Debt $4442.1 mill. **LT Interest** $266.5 mill.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $202.1 mill.
Pension Assets-12/10 $1.41 bill. **Oblig.** $1.63 bill.
Pfd Stock $190.0 mill. **Pfd Div'd** $13.2 mill.
Incl. 1,900,000 shs. 6.70%-7.125% preference, callable at $102.68-$103.50, all $100 par, not subject to mandatory redemption.
Common Stock 200,702,529 shs.
as of 4/29/11
MARKET CAP: $7.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-3.5	-1.2	+4.1
Avg. Indust. Use (MWH)	601	571	516
Avg. Indust. Revs. per KWH (¢)	12.93	11.26	10.75
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Nuclear Capacity Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.3	+.3
Fixed Charge Cov. (%)	156	218	286

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	13.0%	2.0%	*-1.0%*
"Cash Flow"	-2.0%	-8.0%	*8.5%*
Earnings	-5.0%	-16.0%	*18.0%*
Dividends	-2.5%	1.5%	*-4.0%*
Book Value	5.0%	4.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	4812	4756	5323	4926	19818
2009	4303	3864	4027	3403	15598
2010	3586	3309	3968	3474	14340
2011	3570	3360	*4070*	*3500*	*14500*
2012	*3500*	*3300*	*3800*	*3400*	*14000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.81	.95	.35	d1.63	.48
2009	.30	.66	1.00	d.17	1.79
2010	.95	.36	.18	.13	1.61
2011	.35	.49	*.81*	*.65*	*2.30*
2012	*.75*	*.45*	*.60*	*.50*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.3775	.435	.435	.435	1.68
2008	.435	.4775	.4775	.4775	1.87
2009	.4775	.24	.24	.24	1.20
2010	.24	.24	.24	.24	.96
2011	.24	.24	.24		

BUSINESS: Constellation Energy Group, Inc. is a holding company for Baltimore Gas and Electric Company, which distributes electricity and gas in Baltimore and parts of central Maryland. Has 1.2 million electric, 653,000 gas customers. Has nonregulated businesses: Constellation Energy Commodities Group and Constellation NewEnergy. Electric revenue breakdown: residential, 67%; commercial, 26%; industrial, 2%; other, 5%. Generating sources: nuclear, 45%; coal, 37%; gas, 13%; other, 5%. Fuel costs: 76% of revenues. '10 reported depr. rates: generating assets, 2.9%; utility, 3.2%. Has 7,600 employees. Chairman, President & CEO: Mayo A. Shattuck III. Inc.: MD. Address: 100 Constellation Way, Baltimore, MD 21202. Tel.: 410-470-2800. Internet: www.constellation.com.

The proposed acquisition of Constellation Energy by Exelon has received some criticism in Maryland. The deal calls for Constellation stockholders to get 0.93 of a share of Exelon (valued at $39.22) for each of their shares. Each company's shareholders, the regulatory commissions in Maryland and New York, and the Federal Energy Regulatory Commission and other federal agencies must approve the combination. The companies are targeting early 2012 for completion. However, even though Exelon has offered $250 million in merger-related benefits to Maryland ratepayers (including a $100 credit for each residential customer), some intervenor groups believe that this isn't enough and are asking for more.

We now advise Constellation stockholders to sell their shares on the open market. Exelon's offer is reasonable, and Constellation stockholders stand to benefit from a doubling of their dividends if the deal goes through. However, investors should remember that Exelon terminated its agreement to buy Public Service Enterprise Group when the concessions sought by intervenors in New Jersey became more than Exelon was willing to provide. The stock is still trading at a discount of only about 5% to the value of Exelon's offer, which is too low in view of the uncertainty surrounding the regulatory process in Maryland. The Timeliness rank of Constellation stock remains suspended due to the takeover agreement.

Constellation's nonregulated businesses have differing prospects. Low power prices are squeezing margins from the output of the company's generating assets. On the other hand, the retail energy-supply business is benefiting from low prices, which are stimulating customer demand. Constellation has made two acquisitions that expanded its presence in this business materially, from fewer than 300,000 customers to almost a million.

We have cut our 2011 share-net estimate by $0.15, to $2.30, because June-quarter results fell short of our forecast. Our 2012 estimate remains at $2.30. This company's earnings are hard to predict because each quarter's tally contains the effects of unusual items, such as mark-to-market accounting gains or losses.

Paul E. Debbas, CFA *August 26, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 91¢; '03, ($1.09); '04, (8¢); '05, (4¢); '06, 36¢; '07, 22¢; '08, ($7.81); '09, $20.40; '10, ($6.51); gains (loss) from disc. ops.: '05, 13¢; '06, $1.04; '07, (1¢). '10 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '10: $2.26/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '10: 9.86% elec., 9.56% gas; earned on avg. com. eq., '10: 3.6%. Reg. Climate: Below Avg.

Company's Financial Strength	B+
Stock's Price Stability	50
Price Growth Persistence	35
Earnings Predictability	20

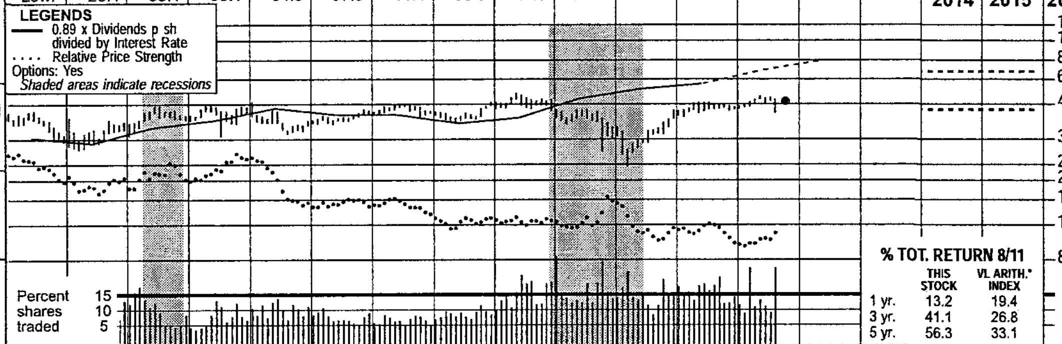
DTE ENERGY CO. NYSE-DTE

RECENT PRICE 49.54 | P/E RATIO 13.4 (Trailing: 13.9 Median: 15.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 2 Raised 8/12/11
SAFETY 3 Lowered 10/5/01
TECHNICAL 3 Lowered 9/16/11
BETA .75 (1.00 = Market)

High:	41.3	47.1	47.7	49.5	45.5	48.3	49.2	54.7	45.3	45.0	49.1	52.8
Low:	28.4	33.1	33.1	34.0	37.9	41.4	38.8	44.0	27.8	23.3	41.3	43.2

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+40%)	13%
Low	45	(-10%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	3	6	0	12	1
to Sell	0	2	0	0	3	6	0	11	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	145	142	162
to Sell	198	178	154
Hld's(000)	94168	97304	96500

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.2	19.4
3 yr.	41.1	26.8
5 yr.	56.3	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
25.05	25.12	25.94	29.10	32.60	39.24	48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	**51.90**	**54.40**	Revenues per sh	**61.75**
7.07	7.10	7.42	7.61	8.40	8.59	6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	**9.50**	**9.95**	"Cash Flow" per sh	**11.25**
3.02	2.80	2.88	3.05	3.33	3.27	2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	**3.60**	**3.75**	Earnings per sh A	**4.25**
2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	**2.32**	**2.42**	Div'd Decl'd per sh B ■	**2.70**
3.13	3.66	3.14	3.83	5.10	5.25	6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	**10.20**	**8.80**	Cap'l Spending per sh	**10.25**
23.68	23.73	24.55	25.49	26.95	28.15	28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	**41.00**	**42.30**	Book Value per sh C	**46.50**
145.12	145.12	145.10	145.07	145.04	142.65	161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	**169.50**	**170.00**	Common Shs Outst'g D	**174.00**
10.0	11.2	10.3	13.3	11.6	10.3	19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	*Bold figures are*		Avg Ann'l P/E Ratio	**13.5**
.67	.70	.59	.69	.66	.67	.99	.62	.78	.85	.73	.94	.97	.89	.69	.79	*Value Line*		Relative P/E Ratio	**.90**
6.9%	6.6%	6.9%	5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	*estimates*		Avg Ann'l Div'd Yield	**4.7%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $7984.0 mill. **Due in 5 Yrs** $3176.0 mill.
LT Debt $7507.0 mill. **LT Interest** $428.0 mill.
Incl. $37.0 mill. capitalized leases, $289.0 mill. Trust Preferred Securities, and $559.0 mill. securitized bonds.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $39.0 mill.
Pension Assets-12/10 $2.91 bill. **Oblig.** $3.79 bill.
Pfd Stock None
Common Stock 169,328,889 shs.

MARKET CAP: $8.4 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
7849.0	6749.0	7041.0	7114.0	9022.0	9022.0	8861.0	9329.0	8014.0	8557.0	**8800**	**9250**	Revenues ($mill)	**10750**
329.0	632.0	480.0	443.0	576.0	437.0	453.0	445.0	532.0	630.0	**620**	**650**	Net Profit ($mill)	**745**
--	--	--	27.1%	26.0%	23.9%	25.1%	34.9%	31.6%	32.7%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
.9%	4.9%	1.3%	.7%	1.0%	5.0%	7.1%	11.2%	2.6%	1.6%	**2.0%**	**2.0%**	AFUDC % to Net Profit	**2.0%**
63.3%	63.0%	59.2%	57.8%	55.1%	56.1%	54.4%	56.4%	54.0%	51.3%	**52.5%**	**51.5%**	Long-Term Debt Ratio	**52.0%**
36.7%	37.0%	40.8%	42.2%	44.9%	43.9%	45.6%	43.6%	46.0%	48.7%	**47.5%**	**48.5%**	Common Equity Ratio	**48.0%**
12517	12350	12956	13154	12849	13323	12824	13736	13648	13811	**14575**	**14825**	Total Capital ($mill)	**16900**
9543.0	9813.0	10324	10491	10830	11451	11408	12231	12431	12992	**13725**	**14175**	Net Plant ($mill)	**15800**
4.4%	7.3%	5.6%	5.2%	6.3%	5.1%	5.3%	5.0%	5.7%	6.3%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.0%**
7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	**9.0%**	**9.0%**	Return on Shr. Equity	**9.0%**
7.2%	13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	**9.0%**	**9.0%**	Return on Com Equity E	**9.0%**
.1%	6.4%	2.5%	1.6%	3.7%	1.2%	1.5%	1.7%	2.9%	4.0%	**3.0%**	**3.0%**	Retained to Com Eq	**3.5%**
99%	53%	72%	80%	63%	84%	80%	77%	65%	57%	**63%**	**63%**	All Div'ds to Net Prof	**63%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.7	-5.6	-.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	11011	10627	11365
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.6	-.8	-.4
Fixed Charge Cov. (%)	205	223	262

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	4.5%	3.0%	3.0%
"Cash Flow"	1.0%	4.5%	3.5%
Earnings	--	2.5%	4.5%
Dividends	.5%	1.0%	4.0%
Book Value	3.5%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2570	2251	2338	2170	9329.0
2009	2255	1688	1950	2121	8014.0
2010	2453	1792	2139	2173	8557.0
2011	2431	2028	**2150**	**2191**	**8800**
2012	**2600**	**2050**	**2250**	**2350**	**9250**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.73	.17	1.03	.80	2.73
2009	1.09	.51	.92	.72	3.24
2010	1.38	.51	.96	.90	3.74
2011	1.04	.67	**.99**	**.90**	**3.60**
2012	**1.15**	**.70**	**1.00**	**.90**	**3.75**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.53	.53	.53	.53	2.12
2008	.53	.53	.53	.53	2.12
2009	.53	.53	.53	.53	2.12
2010	.53	.53	.53	.56	2.15
2011	.56	.56	.5875		

BUSINESS: DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.1 mill. electric, 1.3 mill. gas. Acquired MCN Energy 6/01. Has various nonutility operations. Electric revenue breakdown: residential, 41%; commercial, 33%; industrial, 14%; other, 12%. Generating sources: coal, 72%; nuclear, 14%; gas, 1%; purchased, 13%. Fuel costs: 37% of revenues. '10 reported deprec. rates: 3.3% electric, 2.5% gas. Has 9,800 employees. Chairman, President & CEO: Gerard M. Anderson. Inc.: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary is awaiting a decision on its rate case. Detroit Edison is seeking a rate hike of $361 million, based on a return of 11.125% on a common-equity ratio of 49%. The utility is also asking for a change in its revenue decoupling mechanism so that only the lost volume stemming from energy efficiency measures is considered. Thus, Detroit Edison would benefit from a rebound in kilowatt-hour sales once the service area's economy starts to recover. The staff of the Michigan Public Service Commission (MPSC) is recommending a $162 million rate boost, and an administrative law judge is proposing a raise of $156 million. The staff and ALJ are recommending a 10.15% return on a common-equity ratio of 49%. In April, the utility self-implemented an increase of $107 million, under a regulatory mechanism that is unique to Michigan. The MPSC's order is due in October.

We have raised our 2011 earnings estimate by $0.15 a share, to $3.60. June-quarter profits were better than we expected. Our estimate remains within management's targeted range of $3.40-$3.70 a share. Even so, profits are likely to decline for the year because, in 2010, DTE's nonutility investments benefited from high coke prices and a federal tax credit that wasn't renewed. We look for earnings growth of 4% next year, based on improvement at both the utility and nonutility sides of DTE's operations.

A couple of projects are under development. Detroit Edison is building a 102-megawatt wind project at an expected cost of $250 million. It should be in service in late 2011 or early 2012. DTE has also signed an agreement to build a pipeline and gathering project to serve a gas producer. This investment, which will amount to about $280 million, should begin service in mid-2002.

By utility standards, this timely stock has a yield and 3- to 5-year total return potential that are somewhat above the industry averages. Our long-term projections could prove conservative depending upon the success of DTE's planned monetization of its acreage in the Barnett Shale region of Texas. The company intends to do this in 2012 or early 2013.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 52¢; gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢. '10 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $40.57/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '10 (electric and gas): 11%; earned on avg. com. eq., '10: 9.0%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

EDISON INTERNAT'L NYSE-EIX

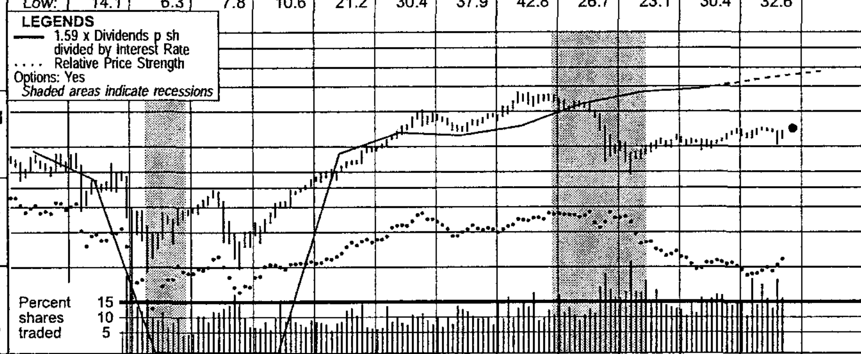
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
39.53	14.2 (Trailing: 12.4, Median: 11.0)	1.01	3.3%

VALUE LINE

TIMELINESS 3 Lowered 3/11/11
SAFETY 3 Raised 11/11/05
TECHNICAL 3 Lowered 9/2/11
BETA .80 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	30.0	16.1	19.6	22.1	32.5	49.2	47.2	60.3	55.7	36.7	39.4	40.2				
Low:	14.1	6.3	7.8	10.6	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6				

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	30	(-25%)	-3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	1	0	1	0	0	0
to Sell	0	0	0	1	0	1	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	184	167	155
to Sell	197	194	210
Hld's(000)	251635	248100	248068

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.0	-4.8
3 yr.	7.0	25.0
5 yr.	7.6	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
18.95	20.13	24.58	29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	***37.45***	***38.65***	Revenues per sh	***44.50***
3.95	4.45	5.49	6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	***7.85***	***8.10***	"Cash Flow" per sh	***9.00***
1.66	1.64	1.75	1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	***2.75***	***2.80***	Earnings per sh A	***3.25***
1.00	1.00	1.00	1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	***1.29***	***1.31***	Div'd Decl'd per sh B ■	***1.40***
2.18	1.75	2.08	2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	***15.65***	***16.25***	Cap'l Spending per sh	***13.25***
14.34	15.07	14.71	14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	***33.85***	***35.30***	Book Value per sh C	***40.25***
443.61	424.52	375.76	350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	***325.81***	***325.81***	Common Shs Outst'g D	***325.81***
10.0	10.8	13.7	15.1	12.9	--	10.0	7.8	7.0	NMF	11.7	13.0	16.0	12.4	9.7	10.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	***12.5***
.67	.68	.79	.79	.74	--	.51	.43	.40	NMF	.62	.70	.85	.75	.65	.66	*estimates*		Relative P/E Ratio	***.85***
6.0%	5.7%	4.2%	3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%			Avg Ann'l Div'd Yield	***3.5%***

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
11436	11488	12135	10199	11852	12622	13113	14112	12374	12409	***12200***	***12600***	Revenues ($mill)	***14500***
536.1	644.0	738.0	220.0	1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	***960***	***985***	Net Profit ($mill)	***1120***
NMF	37.8%	22.4%	--	26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	***32.5%***	***32.0%***	Income Tax Rate	***32.0%***
--	3.3%	3.7%	11.4%	4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	***11.0%***	***11.0%***	AFUDC % to Net Profit	***9.0%***
73.3%	66.6%	68.1%	60.5%	54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	***51.5%***	***51.5%***	Long-Term Debt Ratio	***53.5%***
18.9%	25.6%	31.1%	37.8%	40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	***44.5%***	***44.5%***	Common Equity Ratio	***43.0%***
17279	17352	17299	15995	16167	17725	18375	21374	21185	23861	***24875***	***25800***	Total Capital ($mill)	***30400***
8013.0	8247.0	12587	13475	14469	15913	17403	18969	21966	24778	***28225***	***31825***	Net Plant ($mill)	***39500***
6.6%	6.7%	7.2%	4.2%	9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	***5.5%***	***5.5%***	Return on Total Cap'l	***5.5%***
11.6%	11.1%	13.4%	3.5%	15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	***8.0%***	***8.0%***	Return on Shr. Equity	***8.0%***
13.6%	11.9%	13.6%	3.5%	16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	***8.0%***	***8.5%***	Return on Com Equity E	***8.0%***
13.6%	11.9%	13.6%	NMF	12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	***4.5%***	***4.5%***	Retained to Com Eq	***4.5%***
17%	18%	1%	NMF	29%	31%	33%	35%	41%	40%	***50%***	***49%***	All Div'ds to Net Prof	***46%***

CAPITAL STRUCTURE as of 6/30/11
Total Debt $13397 mill. **Due in 5 Yrs** $2838.0 mill.
LT Debt $12956 mill. **LT Interest** $773.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $1.14 bill.
Pension Assets-12/10 $3.24 bill. **Oblig.** $4.08 bill.
Pfd Stock $1029 mill. **Pfd Div'd** $59.0 mill.
4,800,198 shs. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh. 8,000,000 shs. 5.349%-6.125%, $100 par; 1,250,000 shs. 6.5%, $100 liquidation value.
Common Stock 325,811,206 shs. as of 8/1/11
MARKET CAP: $13 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+1.1	-4.4	-2.7
Avg. Indust. Use (MWH)	711	669	710
Avg. Indust. Revs. per KWH (¢)	6.88	6.95	7.38
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22020	22112	22771
Annual Load Factor (%)	55.6	53.4	50.7
% Change Customers (yr-end)	+.3	+.4	+.5
Fixed Charge Cov. (%)	298	268	240

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.5%	2.5%	2.0%
"Cash Flow"	6.5%	8.0%	1.5%
Earnings	--	10.0%	-1.0%
Dividends	2.5%	15.5%	2.0%
Book Value	9.5%	10.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3113	3477	4295	3227	14112
2009	2812	2834	3678	3050	12374
2010	2810	2742	3788	3069	12409
2011	2782	2983	***3535***	***2900***	***12200***
2012	***2900***	***3000***	***3700***	***3000***	***12600***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.92	.79	1.31	.66	3.68
2009	.78	.78	1.08	.59	3.24
2010	.70	.62	1.46	.58	3.35
2011	.62	.54	***1.05***	***.54***	***2.75***
2012	***.65***	***.55***	***1.05***	***.55***	***2.80***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.29	.29	.29	.29	1.16
2008	.305	.305	.305	.305	1.22
2009	.31	.31	.31	.31	1.24
2010	.315	.315	.315	.315	1.26
2011	.32	.32	.32	.32	

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison (SCE), which supplies electricity to 4.9 million customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Edison Mission Group (EMG) is an independent power producer. Electric revenue breakdown: residential, 40%; commercial, 45%; industrial, 6%; other, 9%. Generating sources: nuclear, 20%; gas, 8%; coal, 6%; hydro, 5%; purchased, 61%. Fuel costs: 33% of revs. '10 reported deprec. rate (utility): 4.1%. Has 20,100 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's utility subsidiary has a rate case pending. Southern California Edison is seeking increases of $824 million next year, $136 million in 2013, and $532 million in 2014. New tariffs will take effect at the start of 2012. The current filing does not deal with the cost of capital. In April of 2012, SCE will put forth a cost-of-capital application.

The utility's prospects are good. SCE is performing well, and its earning power rises as its rate base increases. In fact, the utility forecasts that its rate base will rise at a compounded annual growth rate of 8%-11% through 2014. Despite the positive trends at SCE . . .

Earnings are headed down in 2011. The rise in income we expect from the utility will be outweighed by a significant bottom-line decline at Edison Mission Group (EMG), the nonregulated side of Edison International's business. Low power prices are the problem. In fact, the nonregulated operations are likely to fall into the red this year. Management's earnings guidance of $2.60-$2.90 reflects a $0.19-a-share deficit at EMG, compared with a profit of $0.59 a share in 2010. We expect just a slight earnings recovery for the company as a whole in 2012.

Stricter environmental regulations are a concern for Edison International's nonregulated coal-fired assets. In the current environment of low power prices, the company must decide whether market conditions justify the capital spending needed to keep the plants operating in the long run. Although forward prices for power to be sold in mid-decade suggest that higher environmental costs will eventually be reflected in market prices, this doesn't necessarily mean that Edison will make the upgrades.

We expect a dividend hike at the board meeting in December. This has been the pattern in recent years. We estimate the same $0.02-a-share boost in the yearly disbursement as in the past three years. Edison wants to pay out 45%-55% of *SCE's* (not the company's) earnings, so as long as the utility's income is rising, dividend increases are probable.

This stock's yield is low, by utility standards. Total return potential to 2014-2016 is unexciting, too.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, $1.88; '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; gain (losses) from disc. ops.: '07, (1¢); '09, (2¢); '10, 1¢; '11, (1¢). Incl. nonrec. losses: '00, $7.58; '01, $1.88. '09 & '10 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds historically paid late Jan., Apr., July & Oct. ■ Div'd reinv. plan avail. (C) *Incl. def'd charges. In '10: $13.34/sh.* (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '08: 11.5%; earned on avg. com. eq., '10: 10.8%. Reg. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	55

GREAT PLAINS EN'GY NYSE-GXP

RECENT PRICE	19.19	P/E RATIO	14.3 (Trailing: 15.5, Median: 15.0)	RELATIVE P/E RATIO	1.07	DIV'D YLD	4.3%

VALUE LINE

TIMELINESS 3 Lowered 12/17/10
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Lowered 9/16/11
BETA .75 (1.00 = Market)

High:	29.0	27.6	27.0	32.8	35.7	32.8	32.8	33.4	29.3	20.5	19.9	21.3
Low:	20.9	23.2	15.7	21.4	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3

Target Price Range 2014 | 2015 | 2016

2014-16 PROJECTIONS

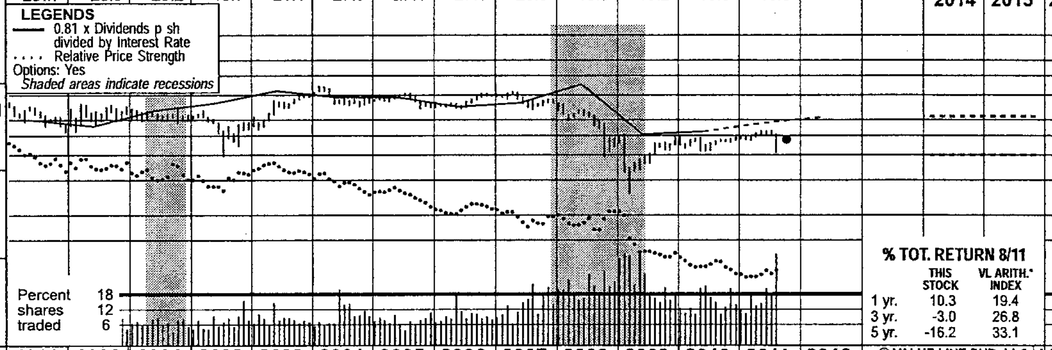
	Price	Gain	Ann'l Total Return
High	25	(+30%)	11%
Low	16	(-15%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	1	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	98	103	107
to Sell	106	96	110
Hld's(000)	90060	94368	94349



% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.3	19.4
3 yr.	-3.0	26.8
5 yr.	-16.2	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
14.31	14.60	14.47	15.17	14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	*16.90*	*16.15*	Revenues per sh	*19.25*
4.06	3.90	3.91	4.21	3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	*3.55*	*3.65*	"Cash Flow" per sh	*4.75*
1.92	1.69	1.69	1.89	1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	*1.20*	*1.45*	Earnings per sh A	*1.75*
1.54	1.59	1.62	1.64	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	*.83*	*.83*	Div'd Decl'd per sh B ■	*1.10*
2.20	1.66	2.05	1.97	2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	*3.75*	*4.05*	Cap'l Spending per sh	*3.50*
14.50	14.71	14.19	14.41	13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	*21.65*	*21.50*	Book Value per sh C	*23.50*
61.91	61.91	61.91	61.91	61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	*136.00*	*155.00*	Common Shs Outst'g D	*155.00*
12.2	15.9	17.0	15.7	20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
.82	1.00	.98	.82	1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.78	*Value Line*		Relative P/E Ratio	*.75*
6.5%	5.9%	5.6%	5.5%	6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3975.8 mill. **Due in 5 Yrs** $1721.1 mill.
LT Debt $2860.8 mill. **LT Interest** $192.5 mill.
Incl. $287.5 mill. 10% equity units subject to mandatory conversion in 2012.
(LT interest earned: 2.0x)
Leases, Uncapitalized Annual rentals $17.9 mill.
Pension Assets-12/10 $353.8 mill.
Oblig. $911.4 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 136,007,431 shs. **as of 7/29/11**
MARKET CAP: $2.6 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
1461.9	1861.9	2149.5	2464.0	2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	*2300*	*2500*	Revenues ($mill)	*3000*
100.0	129.2	159.0	178.8	164.2	127.6	159.2	119.5	135.6	211.7	*165*	*215*	Net Profit ($mill)	*280*
16.6%	27.2%	34.2%	24.1%	18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
12.8%	1.0%	1.8%	2.0%	2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	*6.0%*	*7.0%*	AFUDC % to Net Profit	*4.0%*
53.1%	53.5%	53.8%	44.8%	47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	*52.0%*	*50.5%*	Long-Term Debt Ratio	*51.0%*
44.6%	44.7%	44.4%	53.4%	50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	*47.5%*	*49.0%*	Common Equity Ratio	*48.5%*
1747.4	2102.8	2154.6	2137.1	2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	*6210*	*6840*	Total Capital ($mill)	*7500*
2623.7	2604.1	2700.9	2734.5	2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	*7085*	*7365*	Net Plant ($mill)	*7925*
7.5%	7.7%	9.0%	10.1%	8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
12.2%	13.2%	16.0%	15.1%	13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	*5.5%*	*6.5%*	Return on Shr. Equity	*7.5%*
12.6%	13.6%	16.4%	15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	*5.5%*	*6.5%*	Return on Com Equity E	*7.5%*
NMF	2.3%	4.4%	5.1%	3.2%	NMF	.9%	NMF	.9%	3.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
104%	83%	73%	68%	76%	104%	91%	NMF	81%	54%	*68%*	*57%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+22.5	+18.1	+5.6
Avg. Indust. Use (MWH)	966	1367	1429
Avg. Indust. Revs. per KWH (¢)	5.23	5.47	5.89
Capacity at Peak (Mw)	4164	6336	6272
Peak Load, Summer (Mw)	3495	5347	5531
Annual Load Factor (%)	52.8	51.3	52.8
% Change Customers (avg.)	+.6	-1.2	+.2
Fixed Charge Cov. (%)	188	144	218

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-.5%	-14.5%	*4.0%*
"Cash Flow"	-1.5%	-5.5%	*5.5%*
Earnings	-3.5%	-11.5%	*6.0%*
Dividends	-4.0%	-8.0%	*Nil*
Book Value	4.0%	7.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	297.6	335.0	593.6	443.9	1670.1
2009	419.2	480.5	587.7	477.6	1965.0
2010	506.9	552.0	728.8	467.8	2255.5
2011	492.9	565.1	*742*	*500*	*2300*
2012	*550*	*600*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	d.07	.15	.92	.06	1.16
2009	.05	.28	.57	.10	1.03
2010	.15	.47	.96	d.04	1.53
2011	.01	.31	*.73*	*.15*	*1.20*
2012	*.15*	*.35*	*.80*	*.15*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.415	.415	.415	.415	1.66
2008	.415	.415	.415	.415	1.66
2009	.2075	.2075	.2075	.2075	.83
2010	.2075	.2075	.2075	.2075	.83
2011	.2075	.2075	.2075		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 825,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 41%; commercial, 38%; industrial, 9%; other, 12%. Generating sources: coal, 66%; nuclear, 14%; gas & oil, 2%; wind, 1%; purchased, 17%. Fuel costs: 29% of revs. '10 reported deprec. rate (utility): 3.0%. Has 3,000 employees. Chairman & CEO: Michael J. Chesser. President & COO: Terry Bassham. Inc.: MO. Address: 1200 Main St., Kansas City, MO 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

This has been a difficult year for Great Plains Energy. An extended outage at the Wolf Creek nuclear plant cut share earnings by $0.05 in the June quarter. Flooding in the Midwest has reduced the amount of coal that can be delivered to the company's plants. The reliance on more-costly sources of power is a problem for Kansas City Power & Light, which lacks a fuel adjustment clause in Missouri. This will lower profits by an estimated $0.08-$0.12 a share in the second half of 2011. And, the weak economy is lessening the demand for power. Any volume growth this year is likely to come from the effects of an unusually hot summer. Finally, the service area was hit with severe storms in August. Not all has gone wrong; in June, the utilities received rate hikes in Missouri. All told, Great Plains figures profits will wind up in a range of $1.10-$1.25 a share this year. We have trimmed our estimate by a nickel a share, to $1.20.

Regulatory lag is a problem. The normal delay in recovering costs will hurt share net by an estimated $0.20 this year and $0.22 next year. To combat this problem, the utilities plan to file rate cases in late 2011 or early 2012. They also want the states to institute regulatory mechanisms, such as rate riders and cost trackers, that will enable quicker cost recovery.

We were too optimistic about the company's prospects for 2012. In our June report, we forecasted earnings of $1.60 a share next year, but upon reporting June-quarter results, management issued guidance of $1.35-$1.55 for 2012. So we cut our estimate by $0.15. We now believe a dividend hike won't come until 2013, although we don't rule one out in 2012. Great Plains is targeting a payout ratio of 50%-70%.

The Kansas commission approved a project for environmental retrofits to the LaCygne coal-fired station. The portion of the $615 million project that is allocated to Kansas will be $281 million. The rest of the costs are allocated to Missouri. The utility will have to recover the expenditures through a general rate application in each state.

We believe this stock's yield isn't high enough to compensate investors for the uncertainties that the company is facing.

Paul E. Debbas, CFA *September 23, 2011*

(A) Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on discont. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢; '09, (1¢). '08-'10 EPS don't add due to change in shares or rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '10: $8.05/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '11: 10%; in KS in '10: 10%; earned on avg. com. eq., '10: 7.3%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	70

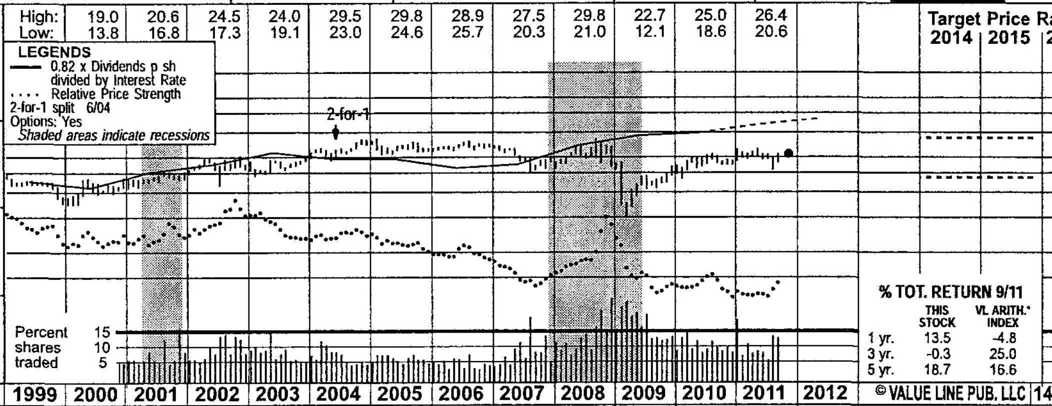
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE **24.96** | P/E RATIO **18.5** (Trailing: 21.0 Median: 19.0) | RELATIVE P/E RATIO **1.31** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS **3** Lowered 11/19/10
SAFETY **3** Lowered 5/8/09
TECHNICAL **3** Lowered 10/28/11
BETA .70 (1.00 = Market)

High:	19.0	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7	25.0	26.4
Low:	13.8	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1	18.6	20.6

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+20%)	9%
Low	19	(-25%)	-1%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	2	0	0	1	0	1
Options	1	0	0	0	0	1	0	0	0
to Sell	1	0	0	2	0	2	1	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	97	91	74
to Sell	81	82	91
Hld's(000)	35955	38026	36557

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	-4.8
3 yr.	-0.3	25.0
5 yr.	18.7	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
21.76	22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	**32.30**	**35.95**	Revenues per sh	**40.25**
2.73	2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	**3.05**	**3.30**	"Cash Flow" per sh	**3.75**
1.33	1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	**1.30**	**1.45**	Earnings per sh A	**2.00**
1.19	1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	**1.24**	**1.24**	Div'd Decl'd per sh B ■ †	**1.30**
3.27	3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	**3.15**	**3.60**	Cap'l Spending per sh	**6.00**
12.25	12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	**15.85**	**16.05**	Book Value per sh C	**18.00**
59.55	61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	**96.00**	**96.00**	Common Shs Outst'g D	**108.00**
13.5	13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**12.0**
.90	.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	*estimates*		Relative P/E Ratio	**.80**
6.6%	6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%			Avg Ann'l Div'd Yield	**5.5%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1440.0 mill. **Due in 5 Yrs** $300.9 mill.
LT Debt $1382.5 mill. **LT Interest** $76.0 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.2x)
Pension Assets-12/10 $832.4 mill.
Oblig. $1.17 bill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100. Sinking fund ends 2018.
Common Stock 95,877,918 shs. as of 7/21/11
MARKET CAP: $2.4 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
1727.3	1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	2309.6	2665.0	**3100**	**3450**	Revenues ($mill)	**4350**
109.8	120.2	120.1	109.6	120.3	109.9	93.6	92.2	84.9	115.4	**125**	**140**	Net Profit ($mill)	**210**
34.6%	34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	34.1%	37.0%	**35.0%**	**35.0%**	Income Tax Rate	**32.0%**
5.9%	4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	20.6%	7.4%	**6.0%**	**8.0%**	AFUDC % to Net Profit	**26.0%**
56.9%	52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	48.0%	44.5%	**45.0%**	**46.5%**	Long-Term Debt Ratio	**46.0%**
41.6%	46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	50.7%	54.3%	**53.5%**	**52.5%**	Common Equity Ratio	**53.0%**
2235.8	2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	2840.8	2732.9	**2840**	**2945**	Total Capital ($mill)	**3700**
2067.5	2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	3088.6	3165.9	**3295**	**3465**	Net Plant ($mill)	**4500**
6.7%	7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	4.3%	5.6%	**5.5%**	**6.0%**	Return on Total Cap'l	**7.0%**
11.4%	11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	5.8%	7.6%	**8.0%**	**9.0%**	Return on Shr. Equity	**10.5%**
11.6%	11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	5.8%	7.7%	**8.0%**	**9.0%**	Return on Com Equity E	**10.5%**
4.4%	4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	NMF	1.4%	**.5%**	**1.5%**	Retained to Com Eq	**3.5%**
63%	63%	64%	87%	85%	93%	89%	93%	NMF	82%	**95%**	**86%**	All Div'ds to Net Prof F	**67%**

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.8	-2.5	-1.1
Avg. Indust. Use (MWH)	6623	6403	6352
Avg. Indust. Revs. per KWH (¢)	25.36	17.68	21.41
Capacity at Yearend (Mw)	2227	2347	2325
Peak Load, Winter (Mw)	1590	1618	1562
Annual Load Factor (%)	75.3	72.2	73.9
% Change Customers (yr-end)	+.1	+.5	+.5
Fixed Charge Cov. (%)	255	234	300

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.0%	3.5%	5.5%
"Cash Flow"	-1.5%	-3.5%	5.5%
Earnings	-2.5%	-6.0%	11.0%
Dividends	--	--	1.0%
Book Value	2.0%	1.0%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	729.6	774.1	915.4	799.8	3218.9
2009	543.8	525.9	620.3	619.6	2309.6
2010	619.0	655.7	694.6	695.7	2665.0
2011	710.6	794.3	**795.1**	**800**	**3100**
2012	**825**	**850**	**875**	**900**	**3450**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.41	.06	.44	.16	1.07
2009	.22	.17	.37	.15	.91
2010	.29	.31	.35	.26	1.21
2011	.30	.28	**.37**	**.35**	**1.30**
2012	**.35**	**.35**	**.40**	**.35**	**1.45**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.31	.31	.31	.31	1.24
2008	.31	.31	.31	.31	1.24
2009	.31	.31	.31	.31	1.24
2010	.31	.31	.31	.31	1.24
2011	.31	.31	.31		

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 446,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources: oil, 60%; purchased, 40%. Fuel costs: 54% of revs. '10 reported depr. rate (util.): 3.5%. Has 3,400 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 900 Richards St., P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Hawaiian Electric Industries is trying to narrow the gap between its utilities' allowed and earned returns on equity. In recent years, the allowed returns on equity of HEI's three utilities have been 10% or higher. The utilities haven't come close to earning their allowed ROEs due to rising expenses and declining kilowatt-hour sales that resulted from the weak economy and energy efficiency measures. For the 12 months that ended on June 30th, their combined ROE was just 5.81%. So, the company proposed regulatory mechanisms that decouple electric revenues and electric volume and provide for annual rate adjustments for capital spending and higher operating and maintenance expenses. HEI's largest utility, Hawaiian Electric Company (HECO), has already been granted these mechanisms (and is benefiting from an interim rate hike of $53.2 million), but the annual adjustments will occur on June 1st, not at the start of the year. This will make it harder for HECO to accomplish its target of earning an ROE that is within one percentage point of its allowed ROE of 10% in 2012.

Maui Electric Company (MECO) has filed a rate case, and Hawaii Electric Light Company (HELCO) will follow suit in 2012. MECO is seeking a tariff hike of $27.5 million (6.7%), based on a return of 11% on a 56.85% common-equity ratio. Once MECO and HELCO receive interim rate orders, they will begin to benefit from the same regulatory mechanisms under which HECO now operates.

The new regulatory mechanisms should boost the company's earning potential. Another benefit to the bottom line is the improved return on assets at American Savings Bank. However, it appears as if the earnings recovery will come more slowly than we had anticipated, so we have cut our 2011 and 2012 share-earnings estimates by $0.10 and $0.05, respectively.

We are not enthusiastic about these shares. Despite the lack of dividend growth for more than a decade—and the likelihood of no increase for a few more years—the yield is less than one percentage point above the utility average. That is not an attractive valuation, in our view.

Paul E. Debbas, CFA *November 4, 2011*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due mid-Feb. (B) Div'ds histor. paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '10: $5.92/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '11: HECO, 10%; in '07: HELCO, 10.7%; in '07: MECO, 10.7%; earned on avg. com. eq., '10: 7.7%. Regul. Climate: Avg. (F) Excl. div'ds paid through reinv. plan.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	20
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

RECENT PRICE	39.83	P/E RATIO	12.8 (Trailing: 14.2 / Median: 15.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	3.0%

VALUE LINE

TIMELINESS 3 Lowered 5/14/10

SAFETY 3 Lowered 2/14/03

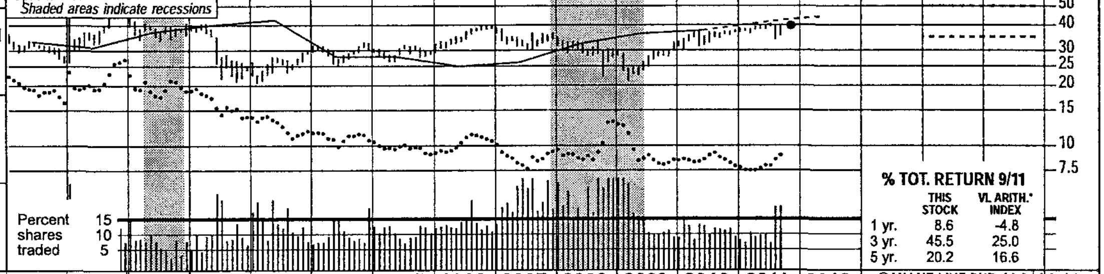
TECHNICAL 3 Lowered 8/12/11

BETA .70 (1.00 = Market)

High:	53.0	49.4	41.0	30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	40.7
Low:	25.9	33.6	20.9	20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9

Target Price Range
2014 | 2015 | 2016

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-10%)	*Nil*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	1	0	0	0
Options	3	0	0	0	0	0	0	0	0
to Sell	4	0	1	3	0	1	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	89	70	62
to Sell	70	91	81
Hld's(000)	33237	34091	34537

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	-4.8
3 yr.	45.5	25.0
5 yr.	20.2	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
14.51	15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	*22.00*	*23.75*	Revenues per sh	*24.50*
3.89	4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	*5.55*	*5.55*	"Cash Flow" per sh	*6.15*
2.10	2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	*3.10*	*3.05*	Earnings per sh A	*3.30*
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	*1.20*	*1.20*	Div'd Decl'd per sh B†■	*1.50*
2.23	2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	*6.50*	*6.00*	Cap'l Spending per sh	*6.70*
18.15	18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	*32.50*	*33.65*	Book Value per sh C	*39.20*
37.61	37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	*50.00*	*50.50*	Common Shs Outst'g D	*51.00*
12.4	13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.83	.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.76	*Value Line*		Relative P/E Ratio	*.85*
7.2%	6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1489.0 mill. Due in 5 Yrs $295.0 mill.
LT Debt $1487.3 mill. LT Interest $75.0 mill.
(LT interest earned: 3.0x)

Pension Assets-12/10 $397.0 mill.
Oblig. $569.9 mill.

Pfd Stock None

Common Stock 49,711,638 shs.
as of 7/29/11

MARKET CAP: $2.0 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
5648.0	928.8	782.7	844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	*1100*	*1200*	Revenues ($mill)	*1250*
130.0	66.3	40.1	77.8	63.7	100.1	82.3	98.4	124.4	142.5	*155*	*155*	Net Profit ($mill)	*170*
33.3%	--	--	--	16.9%	13.3%	14.3%	16.3%	15.2%	NMF	*15.0%*	*30.0%*	Income Tax Rate	*30.0%*
3.1%	3.0%	7.5%	3.9%	4.7%	4.0%	9.7%	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
46.4%	49.2%	50.8%	49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*49.0%*
47.9%	47.9%	46.4%	50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	*53.0%*	*53.0%*	Common Equity Ratio	*51.0%*
1818.0	1826.9	1862.5	1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	*3045*	*3200*	Total Capital ($mill)	*3900*
1886.0	1906.5	2088.3	2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	*3250*	*3400*	Net Plant ($mill)	*4050*
8.7%	5.1%	3.7%	5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
13.3%	7.1%	4.4%	7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	*9.5%*	*9.0%*	Return on Shr. Equity	*8.5%*
14.4%	7.0%	4.2%	7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	*9.5%*	*9.0%*	Return on Com Equity E	*8.5%*
6.3%	NMF	NMF	2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	*6.0%*	*5.5%*	Retained to Com Eq	*4.5%*
58%	113%	NMF	65%	80%	51%	64%	55%	46%	41%	*39%*	*39%*	All Div'ds to Net Prof	*45%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.1	-4.1	-3.1
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	3.65	4.51	4.50
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3214	3014	2714
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+1.6	+.6	+.4
Fixed Charge Cov. (%)	261	280	278

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.5%	1.0%	*2.5%*
"Cash Flow"	--	5.0%	*4.0%*
Earnings	-.5%	11.0%	*4.0%*
Dividends	-4.5%	-2.5%	*4.0%*
Book Value	3.5%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	213.4	230.2	299.7	217.1	960.4
2009	228.6	243.6	324.5	253.1	1049.8
2010	252.5	241.8	309.4	232.3	1036.0
2011	251.1	235.0	*345*	*268.9*	*1100*
2012	*285*	*280*	*355*	*280*	*1200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.48	.39	1.14	.17	2.18
2009	.40	.59	1.16	.49	2.64
2010	.34	.82	1.39	.40	2.95
2011	.60	.42	*1.60*	*.48*	*3.10*
2012	*.60*	*.55*	*1.35*	*.55*	*3.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B†■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.30	.30	.30	.30	1.20
2008	.30	.30	.30	.30	1.20
2009	.30	.30	.30	.30	1.20
2010	.30	.30	.30	.30	1.20
2011	.30	.30	.30		

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 2 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles with estimated population of one million. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 39%; commercial, 22%; industrial, 13%; other, 26%. Fuel and purchased power cost: 30% of '10 revenues; 2010 depreciation rate: 3.0%. Fuel sources: hydro, 51%; thermal, 49%. Has 2,032 employees. Chrmn. & CEO: J. LaMont Kean. Inc.: Idaho. Address: 1221 W. Idaho St., Boise, ID. 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP recently filed a general rate case settlement stipulation. Recall, Idaho Power filed a general rate case back on June 1st requesting an additional $82.6 million in annual revenues. The increase was comprised of approximately $71.3 million related to revenue requirement categories *other than* net power supply expenses (non-NPSE) and $11.3 million associated with net power supply expenses (NPSE). However, several issues in the case were contested, resulting in IDA filing a settlement stipulation on September 23rd. The stipulation provides for a decrease of $25.8 million of the requested non-NPSE recovery, resulting in a $45.5 million increase in the non-NPSE components. The stipulation also provides that $22.8 million associated with the recovery of NPSE would not be included in base rates, but would instead be eligible for 100% cost recovery through Idaho Power's power cost adjustment mechanism. If approved, it would result in a 4.07% overall increase in the utility's base rate revenues, effective January 1, 2012.

We view the settlement stipulation positively. Although the full amount was denied, IDA still receives nearly two-thirds of its original non-NPSE request, which seems relatively fair given the regulatory environment in Idaho. The utility should be able to earn decent returns in 2012.

Langley Gulch is on pace for a mid-2012 completion. The 300-megawatt natural gas-fired plant will immediately become a foundational piece of IDA's energy portfolio. The company may still need to tap equity markets to shore up financing.

The yield is lacking relative to the industry. Shares of IDA are currently yielding 3.0%, more than one full percentage point below the 4.2% utility group average. Indeed, the payout ratio has been on the decline for the past several years. However, with the steady earnings growth we project out to 2014-2016, we believe directors may be in a position to increase the dividend at some point over this time.

Investors seeking utility exposure may find better options elsewhere within the group. Based on our estimates, total return potential over the 3 to 5-year period is below average by utility standards.

Michael Ratty *November 4, 2011*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due early Nov. (B) Div'ds historically paid in late Feb., late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '10: $17.12/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '08: 10.5%; earned on avg. system com. eq., '10: 9.3%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	85

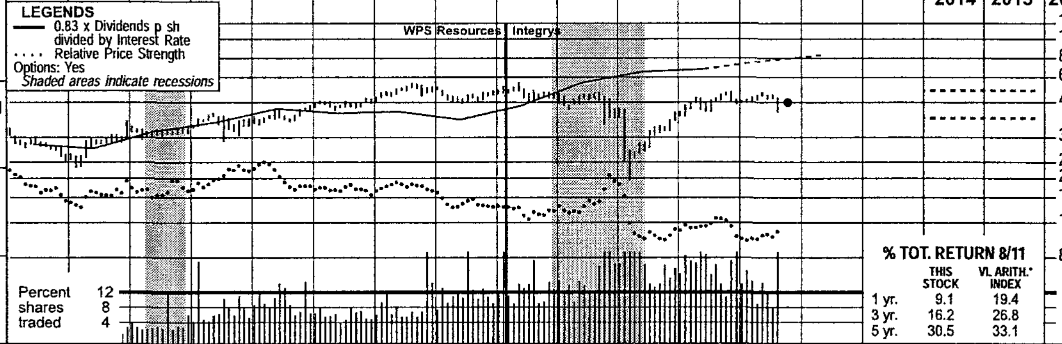
INTEGRYS ENERGY NYSE-TEG

RECENT PRICE 48.20 | P/E RATIO 14.4 (Trailing: 14.1 / Median: 15.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 5.6% | VALUE LINE

TIMELINESS 3 New 3/26/10
SAFETY 2 Raised 6/24/11
TECHNICAL 3 Lowered 9/16/11
BETA .90 (1.00 = Market)

High:	39.0	36.8	42.7	46.8	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.0
Low:	22.6	31.0	30.5	36.8	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+15%)	8%
Low	40	(-15%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	1	0	0	0	0	0	0
Options	0	0	0	0	11	4	0	3	0
to Sell	1	0	0	0	0	8	1	4	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	129	115	122
to Sell	147	149	133
Hld's(000)	40518	40134	40346

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.1	19.4
3 yr.	16.2	26.8
5 yr.	30.5	33.1

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
85.80	83.55	117.07	131.26	173.37	160.01	135.44	184.86	98.71	67.27	***63.20***	***65.15***	Revenues per sh	***73.50***
5.27	5.91	6.23	6.98	7.40	6.33	5.19	4.69	5.34	6.70	***6.65***	***6.95***	"Cash Flow" per sh	***8.00***
2.74	2.74	2.76	4.07	4.09	3.51	2.48	1.58	2.28	3.24	***3.30***	***3.50***	Earnings per sh A	***4.00***
2.08	2.12	2.16	2.20	2.24	2.28	2.56	2.68	2.72	2.72	***2.72***	***2.72***	Div'd Decl'd per sh B ■ †	***2.72***
7.98	7.16	4.77	7.78	10.31	7.94	5.17	7.01	5.85	3.35	***5.40***	***7.60***	Cap'l Spending per sh	***7.75***
22.96	24.45	27.18	29.30	32.47	35.61	42.58	40.79	37.62	37.57	***37.80***	***38.65***	Book Value per sh C	***41.75***
31.18	32.01	36.91	37.26	40.16	43.06	75.99	75.99	75.98	77.35	***78.30***	***78.30***	Common Shs Outst'g D	***78.30***
12.5	14.0	14.9	11.5	13.4	14.7	21.4	30.7	14.8	14.7	***Bold figures are***		Avg Ann'l P/E Ratio	***12.0***
.64	.76	.85	.61	.71	.79	1.14	1.85	.99	.94	***Value Line***		Relative P/E Ratio	***.80***
6.1%	5.5%	5.3%	4.7%	4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	***estimates***		Avg Ann'l Div'd Yield	***5.7%***
2675.5	2674.9	4321.3	4890.6	6962.7	6890.7	10292	14048	7499.8	5203.2	***4950***	***5100***	Revenues ($mill)	***5750***
80.7	94.4	94.5	156.2	157.4	151.6	181.1	124.8	178.2	255.9	***265***	***280***	Net Profit ($mill)	***315***
5.6%	20.8%	26.3%	16.1%	22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	***38.0%***	***38.0%***	Income Tax Rate	***38.0%***
- -	3.2%	2.5%	1.7%	1.0%	.5%	.7%	5.8%	4.5%	.7%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***2.0%***
47.1%	48.3%	45.3%	43.1%	39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	***39.0%***	***39.5%***	Long-Term Debt Ratio	***45.0%***
46.3%	45.8%	52.1%	54.4%	58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	***60.0%***	***59.5%***	Common Equity Ratio	***54.5%***
1544.8	1708.3	1926.2	2008.6	2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	***4920***	***5070***	Total Capital ($mill)	***6025***
1463.6	1610.2	1828.7	2002.6	2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	***5175***	***5510***	Net Plant ($mill)	***6500***
6.8%	7.0%	6.1%	8.8%	8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	***6.5%***	***6.5%***	Return on Total Cap'l	***6.5%***
9.9%	10.7%	9.0%	13.7%	11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	***9.0%***	***9.0%***	Return on Shr. Equity	***9.5%***
10.8%	11.7%	9.1%	14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	***9.0%***	***9.0%***	Return on Com Equity E	***9.5%***
2.7%	3.1%	2.0%	6.6%	5.3%	3.4%	- -	NMF	NMF	2.3%	***1.5%***	***2.0%***	Retained to Com Eq	***3.0%***
76%	74%	79%	54%	56%	65%	99%	NMF	118%	74%	***81%***	***77%***	All Div'ds to Net Prof	***69%***

CAPITAL STRUCTURE as of 6/30/11
Total Debt $2340.1 mill. **Due in 5 Yrs** $1000.6 mill.
LT Debt $2131.6 mill. **LT Interest** $119.4 mill.
(LT interest earned: 4.2x)
Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-12/10 $1.08 bill. **Oblig.** $1.42 bill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.
Common Stock 78,287,906 shs.
as of 7/28/11
MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.9	-4.3	+3.2
Avg. C & I Use (KWH)	14412	NA	NA
Avg. C & I Revs. per KWH (¢)	7.52	NA	NA
Capacity at Peak (Mw)	NA	3346	3078
Peak Load, Summer (Mw)	2171	2403	2421
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.4
Fixed Charge Cov. (%)	149	219	314

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	8.5%	-3.5%	*-7.5%*
"Cash Flow"	- -	-4.0%	*6.0%*
Earnings	1.0%	-8.0%	*9.0%*
Dividends	3.0%	4.0%	*Nil*
Book Value	7.0%	5.5%	*1.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3989	3417	3223	3419	14048
2009	3201	1428	1298	1573	7499.8
2010	1903	1015	998	1287	5203.2
2011	1627	1011	***1012***	***1300***	***4950***
2012	***1650***	***1050***	***1050***	***1350***	***5100***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1.77	.31	d.77	.27	1.58
2009	.89	.45	.63	.31	2.28
2010	.95	.82	.56	.91	3.24
2011	1.56	.38	***.51***	***.85***	***3.30***
2012	***1.60***	***.45***	***.55***	***.90***	***3.50***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.5825	.66	.66	.66	2.56
2008	.67	.67	.67	.67	2.68
2009	.68	.68	.68	.68	2.72
2010	.68	.68	.68	.68	2.72
2011	.68	.68	.68		

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 491,000 electric customers in WI and MI, 1.7 million gas customers in WI, IL, MN, and MI. Also has retail electric and gas marketing operations in the Northeast and Midwest. Electric revenue breakdown: residential, 29%; small commercial & industrial, 29%; larg commercial & industrial, 19%; other, 23%. Generating sources: coal, 62%; other, 4%; purchased, 34%. Fuel costs: 64% of revenues. '10 deprec. rates (utility): 2.4%-3.6%. Has 4,600 employees. Chairman, President & Chief Executive Officer: Charles A. Schrock. Inc.: WI. Address: 130 East Randolph Street, Chicago, IL 60601. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

Integrys Energy's utilities have five rate cases pending. After a disappointing rate order in Wisconsin took effect in early 2011, Wisconsin Public Service put forth a "limited reopener" regulatory filing in which the utility sought an electric tariff increase of $32.2 million. A ruling is expected by yearend. In Michigan, Upper Peninsula Power is seeking an electric rate hike of $7.7 million, based on a 10.75% return on equity. The utility will self-implement a rate increase at the start of 2012, and the commission's order is due in mid-2012. On the gas side, the company's two utilities in Illinois are seeking a total increase of $121.8 million, based on a 10.85% ROE. The state commission's staff is recommending a total raise of $46.8 million, based on an ROE of just 8.75%. A ruling is due by mid-January. In Minnesota, the utility is requesting a $15.6 million increase, based on a 10.75% ROE. It is now collecting interim rate relief of $7.5 million (subject to refund). A decision is targeted for the first quarter of 2012.

The utilities' inability to earn their allowed ROEs is an ongoing problem. That's why so many rate cases are pending. Integrys estimates that this shortfall will hurt net profit by $37 million in 2011. (The comparable figure for 2010 was $20.4 million.) Rate relief will narrow the gap, but almost certainly won't eliminate it.

Integrys Energy Services isn't experiencing the growth that management expected, following a major restructuring in 2010 that refocused this operation both in product line and geographically. Market conditions haven't been as good as expected for retail energy providers such as Integrys. (Management still likes this business and has no plans to exit it.) Thus, we have cut our 2011 and 2012 share-earnings estimates by $0.10 each year, to $3.30 and $3.50, respectively. Our 2011 estimate is within the company's targeted range of $3.24-$3.44.

This stock's main attraction is its high dividend yield. It is more than one percentage point above the utility mean. However, the stock is already trading within our 2014-2016 Target Price Range, and the lack of dividend growth potential suggests that it has little appeal for the long term.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrecur. losses: '09, $3.24; '10, 41¢ net; gains (loss) from discont. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11 (1¢). Next earnings report due early Nov. (B) Div'ds historically paid mid-Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $27.64/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on com. eq. in WI in '11: 10.3%; in IL in '10: 10.23%-10.33%; earned on avg. com. eq, '10: 8.6%. Regulatory Climate: WI, Above Average; IL, Below Average.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	40
Earnings Predictability	45

ITC HOLDINGS CORP. NYSE-ITC

RECENT PRICE	74.50	P/E RATIO	21.7 (Trailing: 24.0 Median: NMF)	RELATIVE P/E RATIO	1.62	DIV'D YLD	1.9%	VALUE LINE

TIMELINESS **3** Lowered 12/3/10

SAFETY **2** Raised 6/24/11

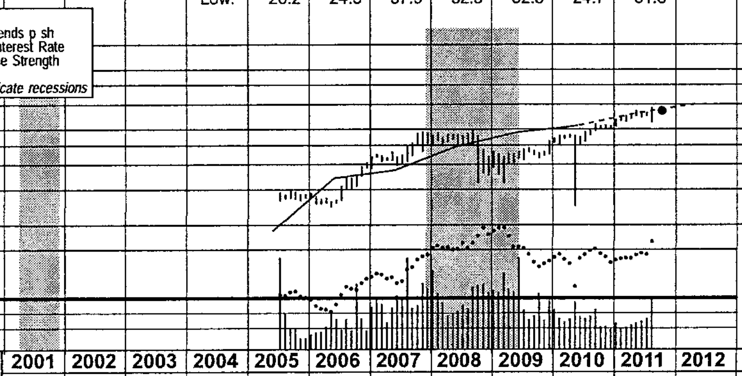
TECHNICAL **3** Lowered 9/9/11

BETA .80 (1.00 = Market)

	2005	2006	2007	2008	2009	2010	2011
High:	30.3	41.2	58.6	60.0	52.8	63.9	77.3
Low:	26.2	24.5	37.9	32.3	32.3	24.7	61.8

Target Price Range
2014 | 2015 | 2016

LEGENDS
— 1.53 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	110	(+50%)	12%
Low	80	(+5%)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	2	1	0	3	0
to Sell	0	0	0	0	2	1	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	107	105	106
to Sell	101	103	98
Hld's(000)	45113	45859	46399

Percent shares traded 18 12 6

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.8	19.4
3 yr.	46.2	26.8
5 yr.	152.2	33.1

ITC Holdings was incorporated in the state of Michigan in 2002 for the purpose of acquiring ITC Transmission, which was a subsidiary of The Detroit Edison Company. The acquisition was completed in 2003. ITC Holdings went public on July 26, 2005, via an initial public offering of 12.5 million shares at $23.00 a share. The deal was underwritten by Lehman Brothers, Morgan Stanley, and Credit Suisse First Boston.

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
--	--	--	4.12	6.18	5.27	9.93	12.44	12.40	13.74	*14.35*	*16.30*	Revenues per sh	*22.00*
--	--	--	1.05	2.04	1.73	3.29	4.11	4.33	4.59	*5.05*	*6.05*	"Cash Flow" per sh	*8.75*
--	--	--	.08	1.06	.92	1.68	2.19	2.58	2.84	*3.30*	*3.85*	Earnings per sh A	*5.50*
--	--	--	--	.53	1.08	1.13	1.19	1.25	1.31	*1.38*	*1.43*	Div'd Decl'd per sh B	*1.70*
--	--	--	2.50	3.57	3.95	6.69	8.09	8.08	7.66	*12.80*	*17.35*	Cap'l Spending per sh	*16.50*
--	--	--	6.41	7.92	12.55	13.12	18.71	20.20	22.03	*24.00*	*26.40*	Book Value per sh C	*35.75*
--	--	--	30.68	33.23	42.40	42.92	49.65	50.08	50.72	*52.00*	*52.75*	Common Shs Outst'g D	*55.00*
--	--	--	--	26.3	33.0	27.6	23.2	17.1	20.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
--	--	--	--	1.40	1.78	1.47	1.40	1.14	1.28	*Value Line*		Relative P/E Ratio	*1.15*
--	--	--	--	1.9%	3.5%	2.4%	2.3%	2.8%	2.3%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*
--	--	--	126.4	205.3	223.6	426.2	617.9	621.0	696.8	*745*	*860*	Revenues ($mill)	*1215*
--	--	--	2.6	34.7	33.2	73.3	109.2	130.9	145.7	*170*	*205*	Net Profit ($mill)	*315*
--	--	--	39.0%	35.3%	29.2%	33.3%	38.1%	37.2%	36.1%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
--	--	--	80.2%	10.1%	15.0%	14.7%	13.8%	13.1%	11.9%	*15.0%*	*17.0%*	AFUDC % to Net Profit	*11.0%*
--	--	--	71.1%	66.3%	70.3%	72.4%	70.8%	70.6%	69.1%	*68.0%*	*65.0%*	Long-Term Debt Ratio	*65.0%*
--	--	--	28.9%	33.7%	29.7%	27.6%	29.2%	29.4%	30.9%	*32.0%*	*35.0%*	Common Equity Ratio	*35.0%*
--	--	--	680.0	780.6	1794.5	2041.5	3177.3	3445.9	3614.3	*3885*	*4010*	Total Capital ($mill)	*5725*
--	--	--	513.7	603.6	1197.9	1960.4	2304.4	2542.1	2872.3	*3445*	*4245*	Net Plant ($mill)	*6350*
--	--	--	2.3%	6.2%	3.0%	5.7%	5.4%	5.7%	6.1%	*6.5%*	*7.0%*	Return on Total Cap'l	*7.5%*
--	--	--	1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	*13.5%*	*14.5%*	Return on Shr. Equity	*15.5%*
--	--	--	1.3%	13.2%	6.2%	13.0%	11.8%	12.9%	13.0%	*13.5%*	*14.5%*	Return on Com Equity E	*15.5%*
--	--	--	1.3%	6.5%	NMF	4.5%	5.4%	6.8%	7.1%	*8.0%*	*9.5%*	Retained to Com Eq	*11.0%*
--	--	--	--	50%	115%	66%	54%	48%	45%	*41%*	*37%*	All Div'ds to Net Prof	*30%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $2565.8 mill. Due in 5 Yrs $780.4 mill.
LT Debt $2565.8 mill. LT Interest $143.7 mill.
(LT interest earned: 2.5x)

Pension Assets-12/10 $24.7 mill. Oblig. $45.1 mill.

Pfd Stock None

Common Stock 51,296,413 shs. as of 7/22/11

MARKET CAP: $3.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2009	2010	6/30/11
Cash Assets	74.9	95.1	81.2
Receivables	72.3	80.4	93.2
Inventory (FIFO)	36.8	42.3	39.7
Other	110.0	33.9	32.8
Current Assets	294.0	251.7	246.9
Accts Payable	43.5	67.0	98.2
Debt Due	--	--	--
Other	103.2	115.4	144.9
Current Liab.	146.7	182.4	243.1
Fix Chg. Cov.	244%	244%	254%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	--	9.5%
"Cash Flow"	--	--	12.5%
Earnings	--	--	14.0%
Dividends	--	--	5.5%
Book Value	--	--	10.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	141.9	160.6	163.3	152.1	617.9
2009	156.0	157.2	151.3	156.5	621.0
2010	161.3	168.5	178.0	189.0	696.8
2011	179.4	185.1	*190*	*190.5*	*745*
2012	*210*	*215*	*215*	*220*	*860*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.53	.57	.56	.54	2.19
2009	.57	.61	.74	.66	2.58
2010	.67	.71	.75	.71	2.84
2011	.81	.83	*.84*	*.82*	*3.30*
2012	*.94*	*.96*	*.99*	*.96*	*3.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.275	.275	.29	.29	1.13
2008	.29	.29	.305	.305	1.19
2009	.305	.305	.32	.32	1.25
2010	.32	.32	.335	.335	1.31
2011	.335	.335	.3525		

BUSINESS: ITC Holdings Corp. engages in the transmission of electricity in the United States. The company operates primarily as a conduit, moving power from generators to local distribution systems either through its own system or in conjunction with neighboring transmission systems. Acquired Michigan Electric Transmission Company 10/06; Interstate Power & Light's transmission assets 12/07. Has assets in Michigan, Iowa, Minnesota, Illinois, Missouri, and Kansas. Operations are regulated by the Federal Energy Regulatory Commission (FERC). '10 reported depreciation rate: 2.4%. Has about 400 employees. Chairman, President & CEO: Joseph L. Welch. Inc.: Michigan. Address: 27175 Energy Way, Novi, Michigan 48377. Tel.: 248-946-3000. Internet: www.itctransco.com.

ITC Holdings is not like other electric utilities. It is the sole publicly traded transmission-only company. The company operates under a formula-based ratemaking system that accounts for expected capital spending and increases in operating expenses. (Certain costs, such as developmental expenses, are not reflected in the formula.) ITC's four subsidiaries are allowed very healthy returns on equity of 12.16% to 13.88%. As the statistical array above shows, earnings have risen rapidly since 2007. Profits should continue to advance as the company's growing capital budget is reflected in rates. With the release of second-quarter results, management raised its 2011 earnings target by a nickel a share, to $3.25-$3.35. We are sticking with our estimate of $3.30, which is at the midpoint of this range. Our 2012 forecast remains $3.85 a share.

The company has plenty of opportunities to invest capital. A good deal of maintenance capital spending is necessary, especially at one subsidiary, ITC Midwest, which has an aging system that is in the bottom quartile in sustained outages. (Two other ITC subsidiaries are in the top docile.) The company also builds transmission that is needed for renewable projects. Finally, the company's newest unit, ITC Great Plains, has three projects, which are on budget and on schedule, that will expand transmission capacity in Kansas, Nebraska, and Oklahoma. ITC Great Plains plans to spend $517 million on these projects from 2011 through 2015.

The board of directors raised the dividend last month. The hike was $0.07 a share (5.2%) annually, which is within ITC's goal of 4%-5% yearly growth in the disbursement. Even after the increase, however, the yield is not just low for a utility, but is below the median of all dividend-paying stocks under our coverage. Unlike for the typical utility issue, investors focus more on total return than on just dividends.

We have a neutral opinion of ITC stock. The company's solid performance and good prospects have not gone unnoticed. The stock is up 20% this year. At the current quotation, it doesn't stand out for either the year ahead or the 3- to 5-year period.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted earnings. Quarterly earnings don't add to full-year total in '08 due to rounding. Next earnings report due late October.
(B) Quarterly dividend initiated 9/16/05. Dividends historically paid in early March, June, September, and December.
(C) Includes intangibles. In '10: $1.2 billion, $22.91/sh. (D) In millions.
(E) Rates allowed on common equity: 12.16%-13.88%. Earned on avg. common equity, '10: 13.5%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	85
Earnings Predictability	55

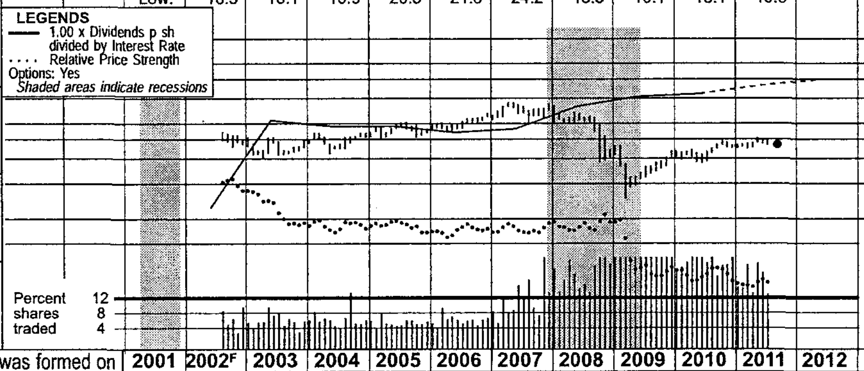
PEPCO HOLDINGS NYSE-POM

RECENT PRICE **18.86** | P/E RATIO **15.3** (Trailing: 12.9 Median: NMF) | RELATIVE P/E RATIO **1.13** | DIV'D YLD **5.7%** | **VALUE LINE**

TIMELINESS 3 Raised 2/5/10
SAFETY 3 Lowered 6/6/03
TECHNICAL 2 Raised 7/29/11
BETA .80 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	21.9	20.6	21.7	24.5	27.0	30.7	29.6	18.7	19.8	20.4
Low:	18.3	16.1	16.9	20.3	21.8	24.2	15.3	10.1	15.1	16.6

Target Price Range
2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+60%)	16%
Low	18	(-5%)	5%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	150	161	152
to Sell	119	132	134
Hld's(000)	125477	115863	125507

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.0	21.2
3 yr.	-8.6	42.7
5 yr.	0.8	48.6

Pepco Holdings, Inc. (PHI) was formed on August 1, 2002, upon the merger of Potomac Electric Power Co. (PEPCO) and Conectiv. In the $2.2 billion deal, PEPCO common stockholders received one common share in PHI for each of their shares, and Conectiv investors exchanged each of their common shares for $25 worth of PHI stock and cash, prorated 50/50.

2001	2002F	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
50.20	41.11	42.33	38.35	42.49	43.57	46.71	48.88	41.66	31.27	*29.50*	*27.25*	Revenues per sh	*28.00*
4.87	3.12	3.80	3.71	3.67	3.47	3.30	3.55	2.82	2.97	*3.00*	*3.00*	"Cash Flow" per sh	*3.65*
2.16	1.79	1.35	1.46	1.49	1.33	1.53	1.93	1.06	1.24	*1.25*	*1.25*	Earnings per sh A	*1.65*
--	.42	1.00	1.00	1.00	1.04	1.04	1.08	1.08	1.08	*1.08*	*1.08*	Div'd Decl'd per sh B ■	*1.16*
5.35	3.06	3.48	2.75	2.46	2.47	3.11	3.57	3.89	3.56	*4.40*	*4.60*	Cap'l Spending per sh	*4.00*
18.41	18.17	17.48	17.87	18.88	18.82	20.04	19.14	19.15	18.79	*19.00*	*20.00*	Book Value per sh C	*21.20*
158.70	164.85	171.77	188.33	189.82	191.93	200.51	218.91	222.27	225.08	*227.00*	*235.00*	Common Shs Outst'g D	*250.00*
--	11.3	13.4	13.6	14.9	18.1	18.2	12.2	13.7	14.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
--	.62	.76	.72	.79	.98	.97	.73	.91	.90	*estimates*		Relative P/E Ratio	*.95*
--	2.1%	5.5%	5.0%	4.5%	4.3%	3.7%	4.6%	7.4%	6.2%			Avg Ann'l Div'd Yield	*5.0%*
7966.5	6777.3	7271.3	7221.8	8065.5	8362.9	9366.4	10700	9259.0	7039.0	*6700*	*6400*	Revenues ($mill)	*7000*
368.0	294.9	245.2	261.3	277.4	254.4	296.5	400.0	235.0	276.0	*285*	*290*	Net Profit ($mill)	*410*
36.8%	17.0%	18.3%	38.7%	38.8%	39.1%	39.3%	29.6%	31.9%	18.8%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
4.5%	--	--	--	--	--	--	--	--	--	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
53.1%	58.7%	63.1%	59.7%	57.1%	54.6%	54.1%	56.2%	53.8%	49.0%	*48.0%*	*48.5%*	Long-Term Debt Ratio	*48.0%*
41.0%	36.4%	35.6%	39.6%	42.3%	45.1%	45.9%	43.8%	46.2%	51.0%	*52.0%*	*51.5%*	Common Equity Ratio	*52.0%*
7123.0	8228.9	8439.3	8494.0	8469.3	8004.0	8753.0	9568.0	9203.0	8292.0	*8300*	*9100*	Total Capital ($mill)	*10200*
6352.0	6798.0	6964.9	7088.0	7312.0	7576.6	7876.7	8314.0	8863.0	7673.0	*7700*	*7750*	Net Plant ($mill)	*8000*
6.8%	4.6%	4.8%	5.0%	5.0%	5.1%	5.1%	5.8%	4.5%	5.1%	*5.0%*	*5.0%*	Return on Total Cap'l	*7.0%*
11.0%	8.7%	7.9%	7.6%	7.6%	7.0%	7.4%	9.5%	5.5%	6.5%	*6.5%*	*6.0%*	Return on Shr. Equity	*7.5%*
12.6%	9.2%	7.7%	7.7%	7.7%	7.0%	7.4%	9.5%	5.5%	6.5%	*6.5%*	*6.0%*	Return on Com Equity E	*7.5%*
12.6%	5.3%	2.0%	2.5%	2.4%	1.5%	2.3%	4.2%	NMF	.8%	*1.0%*	*1.0%*	Retained to Com Eq	*2.5%*
--	46%	75%	68%	69%	78%	68%	56%	101%	87%	*8.5%*	*88%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $4205 mill. **Due in 5 Yrs** $1450 mill.
LT Debt $3795 mill. LT Interest $300 mill.
(LT interest earned: 2.0x)

Pension Assets-12/10 $1.6 bill. **Oblig.** $2.0 bill.

Pfd Stock None

Common Stock 225,395,875 shs.
as of 7/31/11

MARKET CAP: $4.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.6	-2.5	+4.1
Avg. Resid'l Use (KWH)	10503	10395	11253
Avg. Resid'l Revs. per KWH(¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	4606	4647	N/A
Peak Load, Summer (Mw)	N/A	N/A	N/A
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	Nil	+.6	+1.1
Fixed Charge Cov. (%)	263	188	204

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-1.0%	--	*NMF*
"Cash Flow"	-3.5%	-3.5%	*2.5%*
Earnings	-.5%	-.5%	*2.5%*
Dividends	--	1.5%	*1.0%*
Book Value	.5%	1.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	2640	2518	3059	2481	10700
2009	2520	2065	2539	2135	9259
2010	1819	1636	2067	1517	7039
2011	1634	1409	*2000*	*1657*	*6700*
2012	*1600*	*1500*	*1800*	*1500*	*6400*

Cal-endar	EARNINGS PER SHARE AG Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.49	.53	.59	.32	1.93
2009	.21	.11	.56	.18	1.06
2010	.16	.34	.52	.25	1.24
2011	.27	.42	*.41*	*.15*	*1.25*
2012	*.25*	*.30*	*.45*	*.25*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.26	.26	.26	.26	1.04
2008	.27	.27	.27	.27	1.08
2009	.27	.27	.27	.27	1.08
2010	.27	.27	.27	.27	1.08
2011	.27	.27			

BUSINESS: Pepco Holdings, Inc. consists mainly of three electric utility subsidiaries: Potomac Electric Power Co., serving Washington, D.C. and adjoining areas of Maryland; Delmarva Power, which serves the peninsula area of Delaware, Maryland and Virginia; and Atlantic City Electric, serving southern New Jersey. In July 2010, Pepco sold competitive energy business (Conectiv Energy) to Calpine Corp. Electricity customers: 1.8 million; gas customers: 123,000. Electricity breakdown: residential, 30%; commercial, 49%; other, 21%. 2010 depreciation rate: 2.6%. Has approximately 5,014 employees as of 12/31/10. Chrmn., Pres. & CEO: Joseph M. Rigby. Inc.: DE. Address: 701 Ninth Street, N.W., Wash., D.C. 20068. Telephone.: 202-872-2000. Internet: www.pepcoholdings.com.

We have raised our 2011 earnings estimate for Pepco Holdings. The Washington, DC-based utility reported second-quarter earnings of $0.42 a share, easily surpassing our estimate of $0.25. The beat can be attributed to better-than-expected power delivery earnings, reasonable regulatory treatment, and an income tax adjustment. The company realized a tax benefit of $17 million ($0.08 a share) in the quarter stemming from a resolution with the IRS related to a previous settlement. All told, we have added a nickel to our full-year earnings estimate, now $1.25 a share. Management reaffirmed its guidance of $1.10-$1.25, noting the result would likely come in at the upper end of the range.

Maryland regulators approved a settlement agreement in Delmarva Power's electric base rate case. The Maryland Commission granted an annual rate increase of $12 million, or 1.4%, effective July 8th. Although the return on equity was not specified, an ROE of 10% was authorized for purposes of calculating the allowance for funds used under construction and regulatory asset carrying charges. In our view, the 10% ROE will likely be representative of the actual figure. The commission also established a group that will explore methods to address regulatory lag issues.

The MAPP transmission project may experience further delays. The PJM's power needs assessment for the project is still ongoing with a completed evaluation expected by the end of August. Although Pepco believes MAPP will be needed eventually, it thinks that it is going to be pushed back further than the original June, 2015 in-service date (which management indicated could be several years). Any sort of delay will likely have a negative impact on our long-term earnings outlook, and also result in a restructuring of the company's five-year construction expenditure forecast.

This neutrally ranked stock offers one of the highest yields in the industry. Shares of POM are currently yielding an attractive 5.7%, well above the utility mean of 4.4%. Income-oriented investors may want to consider taking a position here.

Michael Ratty *August 26, 2011*

(A) Based on dil. shs. Excl. nonrecur. items: '01, 30¢; '03, d69¢; '04, 1¢; '05, 47¢; '06, d1¢; '08, 46¢; '10, 62¢. Next egs rpt early Nov. (B) Div'ds paid in late March, June, Sep., and Dec. ■ Div'd reinvest. plan. (C) Incl. def'd chgs: '09, $2.6 bill. or $11.70/sh. (D) In mill. (E) Rate allowed in MD: 9.83% ('10-Pepco), 10.0% ('09-Delmarva); DC: 9.6% ('10-Pep.); DEL: 10.0% ('06-Del.); NJ: 10.3% ('10-ACE); Earned on '10 avg. com. eq., 6.5%. Reg. Clim.: Avg. (F) Pre-'03 results pro forma. (G) Qtrly egs. may not add due to chng. in shs.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	70

PG&E CORP. NYSE-PCG

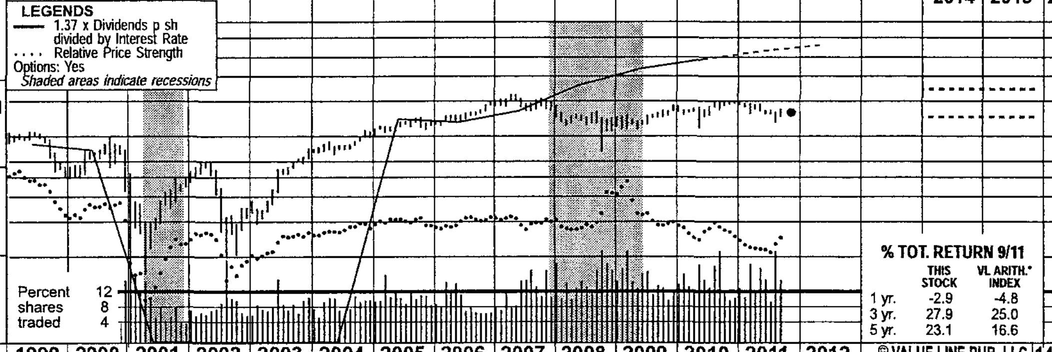
RECENT PRICE **42.22** | P/E RATIO **14.1** (Trailing: 15.6 / Median: 14.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **4.3%** | VALUE LINE

TIMELINESS **2** Raised 9/2/11
SAFETY **2** Raised 5/12/06
TECHNICAL **2** Raised 10/14/11
BETA .55 (1.00 = Market)

High:	31.8	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0
Low:	17.0	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7	34.5	34.9	37.6

Target Price Range 2014 | 2015 | 2016

LEGENDS
—— 1.37 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	11%
Low	40	(-5%)	4%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	2	0	1	0	0	1
to Sell	0	0	0	10	0	1	0	0	1

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	215	190	194
to Sell	190	221	211
Hld's(000)	265396	272189	281663

Percent shares traded 12 8 4

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.9	-4.8
3 yr.	27.9	25.0
5 yr.	23.1	16.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
23.24	23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	**36.30**	**36.90**	Revenues per sh	**44.75**
6.31	5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	**8.45**	**9.25**	"Cash Flow" per sh	**10.75**
2.95	2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	**2.75**	**3.55**	Earnings per sh A	**4.25**
1.96	1.77	1.20	1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	**1.82**	**1.82**	Div'd Decl'd per sh B ■ †	**2.20**
2.25	3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	**9.90**	**10.95**	Cap'l Spending per sh	**12.25**
20.77	20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	**29.80**	**32.00**	Book Value per sh C	**38.00**
414.03	403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	**405.00**	**420.00**	Common Shs Outst'g D	**425.00**
9.4	10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**11.5**
.63	.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	*estimates*		Relative P/E Ratio	**.75**
7.1%	7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%			Avg Ann'l Div'd Yield	**4.5%**

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
22959	12495	10435	11080	11703	12539	13237	14628	13399	13841	**14700**	**15500**	Revenues ($mill)	**19000**
1099.0	d874.0	791.0	901.0	904.0	1005.0	1020.0	1198.0	1168.0	1113.0	**1120**	**1485**	Net Profit ($mill)	**1840**
35.6%	--	36.7%	35.0%	37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	**33.5%**	**33.5%**	Income Tax Rate	**33.5%**
1.6%	--	3.7%	3.6%	5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	**11.0%**	**9.0%**	AFUDC % to Net Profit	**8.0%**
58.9%	51.5%	42.4%	45.1%	48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	**48.5%**	**47.0%**	Long-Term Debt Ratio	**45.5%**
34.9%	42.8%	53.9%	53.2%	50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	**50.5%**	**52.0%**	Common Equity Ratio	**53.5%**
12399	8438.0	7815.0	16242	14446	16696	18558	20163	21793	22863	**23875**	**25875**	Total Capital ($mill)	**30200**
19167	16928	18107	18989	19955	21785	23656	26261	28892	31449	**33125**	**35300**	Net Plant ($mill)	**42400**
13.3%	NMF	16.3%	7.6%	8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	**6.0%**	**7.0%**	Return on Total Cap'l	**7.5%**
21.5%	NMF	17.6%	10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	**9.0%**	**11.0%**	Return on Shr. Equity	**11.5%**
22.9%	NMF	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	**9.0%**	**11.0%**	Return on Com Equity E	**11.5%**
22.9%	NMF	18.5%	10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	**3.0%**	**5.5%**	Retained to Com Eq	**5.5%**
10%	--	2%	1%	39%	47%	50%	47%	52%	61%	**66%**	**51%**	All Div'ds to Net Prof	**52%**

CAPITAL STRUCTURE as of 6/30/11
Total Debt $13362 mill. **Due in 5 yrs** $3646 mill.
LT Debt $11689 mill. **LT Interest** $617.0 mill.
Incl. $223.0 mill. Energy Recovery Bonds.
(LT interest earned: 3.3x)
Pension Assets-12/10 $10.3 bill. **Oblig.** $12.1 bill.
Pfd Stock $252.0 mill. **Pfd Div'd** $14.0 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 401,657,362 shs.

MARKET CAP: $17 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+2.3	-2.8	-2.0
Avg. Indust. Use (MWH)	12765	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.67	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.3	+.2	+.5
Fixed Charge Cov. (%)	288	296	303

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-4.5%	6.0%	3.0%
"Cash Flow"	6.0%	7.5%	4.5%
Earnings	--	7.0%	6.0%
Dividends	3.5%	--	4.5%
Book Value	5.5%	10.5%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	3733	3578	3674	3643	14628
2009	3431	3194	3235	3539	13399
2010	3475	3232	3513	3621	13841
2011	3597	3684	**3700**	**3719**	**14700**
2012	**3950**	**3750**	**3850**	**3950**	**15500**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.62	.80	.83	.97	3.22
2009	.65	.87	.80	.71	3.03
2010	.67	.86	.66	.63	2.82
2011	.50	.91	**.75**	**.59**	**2.75**
2012	**.75**	**.95**	**.95**	**.90**	**3.55**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.33	.36	.36	.36	1.41
2008	.36	.39	.39	.39	1.53
2009	.39	.42	.42	.42	1.65
2010	.42	.455	.455	.455	1.79
2011	.455	.455	.455	.455	

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.1 million electric and 4.3 million gas customers. Electric revenue breakdown: residential, 40%; commercial, 38%; industrial, 12%; agricultural, 7%; other, 3%. Generating sources: nuclear, 24%; hydro, 13%; gas, 5%; purchased, 58%. Fuel costs: 37% of revenues. '10 reported depreciation rate (utility): 3.4%. Has 19,400 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

PG&E is incurring sizable costs associated with the explosion in 2010 of its gas pipeline in San Bruno, California. The company's latest estimate of the direct expenses associated with the accident is $413 million (pretax) in 2011. Of this amount, $126 million was recorded in the first half. PG&E is also accruing reserves for potential third-party claims. This amounted to $220 million in 2010, $59 million in the first half of 2011, and will probably be as much as $180 million for the full year. Insurance should cover most of the third-party claims, and the company recovered $60 million in the first half. These costs and insurance recoveries are *included* in our earnings presentation. For 2012, PG&E forecasts direct expenses of $274 million. Its proposed pipeline safety enhancement plan suggests that all but $43 million is recoverable in rates. The plan also includes over $1.4 billion of capital costs from 2011 through 2014. The California Public Utilities Commission (CPUC) must issue a ruling on the plan.

The National Transportation Safety Board's report criticized the company. This was not surprising, and PG&E has acknowledged that changes are in order. The CPUC is conducting its own investigation, and has the authority to fine the utility. We would *exclude* a sizable fine from our earnings presentation.

Another year of weak earnings is likely in 2011, but we look for better results in 2012. The direct expenses associated with the San Bruno accident affect our estimates significantly, and have obviated the benefits of the rate relief that the utility was granted earlier this year. As for the dividend, PG&E has stated that there will be no increase in 2011. We expect no raise next year, as well. Note that PG&E has a new chief executive, Tony Earley (formerly of DTE Energy).

Even after the stock's underperformance since the accident, the yield and 3- to 5-year total return potential are only about average for a utility. The stock's favorable Timeliness rank is due, in part, to the fact that insurance recoveries ($0.09 a share in the June quarter) aren't included in our earnings estimates because the timing and amount of these are impossible to predict.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95; '09, 18¢; gain from discontinued ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. Next earnings report due late Feb. (B) Div'ds historically paid in mid-Jan., Apr., July, Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '10: $14.79/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%; earned on avg. com. eq., '10: 10.0%. Regulatory Climate: Above Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	90

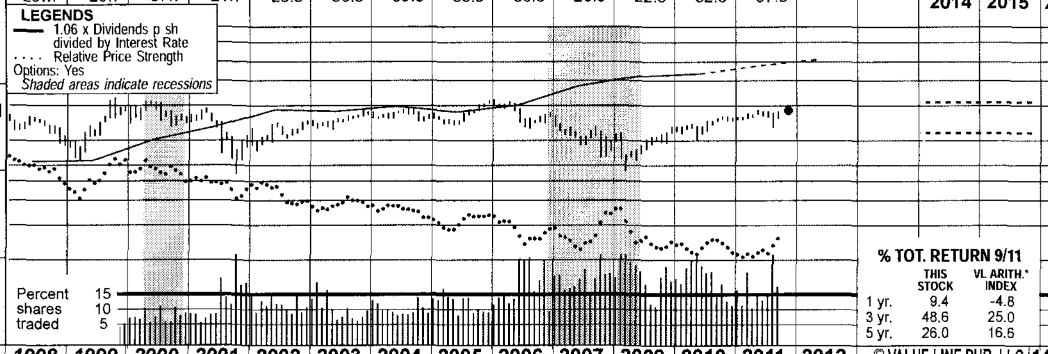
PINNACLE WEST NYSE-PNW

RECENT PRICE 45.43 | P/E RATIO 15.7 (Trailing: 16.3 / Median: 14.0) | RELATIVE P/E RATIO 1.11 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 3 Raised 1/29/10
SAFETY 2 Raised 5/6/11
TECHNICAL 3 Lowered 9/16/11
BETA .70 (1.00 = Market)

High:	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	46.4
Low:	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3

Target Price Range
2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	7%
Low	35	(-25%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	127	126	144
to Sell	151	149	146
Hld's(000)	77797	79145	81484

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.4	-4.8
3 yr.	48.6	25.0
5 yr.	26.0	16.6

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	32.50	30.01	29.75	31.80	Revenues per sh	31.25
5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.08	6.85	6.80	7.55	"Cash Flow" per sh	8.00
1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.26	3.08	2.75	3.25	Earnings per sh A	3.50
.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	Div'd Decl'd per sh B ■	2.30
2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	7.64	7.03	9.15	9.85	Cap'l Spending per sh	8.25
20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	32.69	33.86	34.50	35.60	Book Value per sh C	39.25
87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	101.43	108.77	109.25	110.00	Common Shs Outst'g D	123.00
9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	13.7	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	12.0
.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.91	.80	*Value Line*		Relative P/E Ratio	.80
4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.8%	5.4%	*estimates*		Avg Ann'l Div'd Yield	5.5%
						3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.7	3523.6	3297.1	3263.6	3250	3500	Revenues ($mill)	3850
						283.6	312.2	215.2	230.6	235.2	223.2	317.1	298.8	229.2	330.4	300	360	Net Profit ($mill)	430
						44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	36.9%	31.9%	34.0%	34.5%	Income Tax Rate	34.5%
						7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	11.1%	14.8%	11.2%	11.7%	13.0%	13.0%	AFUDC % to Net Profit	9.0%
						45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	50.4%	45.3%	49.0%	52.0%	Long-Term Debt Ratio	46.0%
						54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	49.6%	54.7%	51.0%	48.0%	Common Equity Ratio	54.0%
						4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.7	6658.7	6686.6	6729.1	7415	8150	Total Capital ($mill)	8950
						5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	9257.8	9578.8	10135	10750	Net Plant ($mill)	12200
						8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	4.8%	6.5%	5.5%	6.0%	Return on Total Cap'l	6.5%
						11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	8.0%	9.0%	Return on Shr. Equity	9.0%
						11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	8.0%	9.0%	Return on Com Equity E	9.0%
						6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	.7%	3.1%	2.0%	3.5%	Retained to Com Eq	3.0%
						43%	41%	64%	68%	71%	85%	63%	70%	89%	66%	76%	64%	All Div'ds to Net Prof	65%

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3672.5 mill. **Due in 5 Yrs** $2071.2 mill.
LT Debt $2761.7 mill. **LT Interest** $167.1 mill.
Incl. $83.1 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $24.0 mill.
Pension Assets-12/10 $1.78 bill. **Oblig.** $2.35 bill.
Pfd Stock None

Common Stock 109,110,950 shs.
as of 7/26/11
MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.3	-2.2	-1.6
Avg. Indust. Use (MWH)	665	619	619
Avg. Indust. Revs. per KWH (¢)	7.91	8.11	7.83
Capacity at Peak (Mw)	8457	8635	8682
Peak Load, Summer (Mw)	7026	7218	6396
Annual Load Factor (%)	51.2	49.3	50.0
% Change Customers (yr-end)	+.9	+.5	+.4
Fixed Charge Cov. (%)	221	248	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	.5%	-.5%
"Cash Flow"	--	3.0%	.5%
Earnings	-2.5%	.5%	6.0%
Dividends	4.5%	3.0%	1.5%
Book Value	2.5%	.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	709.8	898.0	1072.9	686.4	3367.1
2009	625.9	836.0	1142.2	693.0	3297.1
2010	620.3	820.6	1139.1	683.6	3263.6
2011	659.6	799.8	1100	690.6	3250
2012	675	850	1250	725	3500

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	d.04	1.13	1.50	d.48	2.12
2009	d.36	.74	2.07	d.19	2.26
2010	.07	.83	2.08	.06	3.08
2011	d.14	.78	2.06	.05	2.75
2012	Nil	.95	2.25	.05	3.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.525	.525	.525	.525	2.10
2008	.525	.525	.525	.525	2.10
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525		

BUSINESS: Pinnacle West Capital Corporation is a holding company for *Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in 11 of 15 Arizona counties.* Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 47%; commercial, 39%; industrial, 5%; other, 9%. *Generating sources:* coal, 37%; nuclear, 27%; gas, 12%; purchased, 24%. Fuel costs: 36% of revenues. Has 7,200 employees. *'09 reported depreciation rate: 3.1%. Chairman, President & Chief Executive Officer:* Donald E. Brandt. Incorporated: Arizona. Address: 400 North Fifth Street, Post Office Box 53999, Phoenix, Arizona 85072-3999. Telephone: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has a general rate case pending. Arizona Public Service filed for a tariff hike of $194.1 million (6.6%), based on a return of 11% on a common-equity ratio of 53.9%. APS is asking for a regulatory mechanism that decouples electric volume and revenues, and a tracker that raises rates annually to recover infrastructure additions for generating assets and environmental compliance. The utility also wants to revise the fuel adjustment clause so that it accounts for all changes in fuel costs, not just 90% of them. (Other utilities in the state have 100% pass-through of fuel costs.) New tariffs won't take effect until mid-2012, at the earliest. Settlement talks will begin in the next several weeks.

Milder-than-normal weather conditions have prompted us to cut our 2011 earnings estimate. We reduced our estimate by $0.30 a share, to $2.75. That's at the low end of the company's guidance of $2.75-$2.90 a share. We continue to forecast share net of $3.25 in 2012, assuming APS receives a decent rate order and weather patterns return to normal.

The utility is awaiting regulatory approval for an asset acquisition. APS has agreed to pay $294 million for Southern California Edison's 739-megawatt stake in units 4 and 5 of the Four Corners coal-fired plant. The company would finance the purchase with a mix of debt and equity. APS would have to spend $300 million on environmental upgrades, but would be able to avoid more than $600 million needed for units 1, 2, and 3, which would be shut down. The transaction is expected to close in late 2012. Our figures will not reflect the deal until after it has been completed.

APS is adding solar capacity. In the first phase, it plans to build 100 mw at a cost of up to $500 million. APS has procured 83 mw, so far, at a cost of $384 million. The utility is proposing to add 100 mw more for up to $475 million.

This stock's yield isn't high enough to compensate investors for low dividend growth potential. Not only is the share price within our 3- to 5-year Target Price Range, it remains closer to the high end than the low end. Thus, total return potential over that time frame is modest.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted egs. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 1¢. '08 EPS don't add due to rounding, '10 due to change in shares. Next earnings report due mid-Feb. **(B)** Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '10: $11.28/sh. **(D)** In mill. **(E)** Rate base: Fair value. Rate allowed on com. eq. in '10: 11%; earned on avg. com. eq., '10: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	65

PORTLAND GENERAL NYSE-POR

RECENT PRICE **24.37** | P/E RATIO **13.7** (Trailing: 11.1 / Median: NMF) | RELATIVE P/E RATIO **0.97** | DIV'D YLD **4.4%** | VALUE LINE

High:	35.0	31.3	27.7	21.4	22.7	26.0		
Low:	24.2	25.5	15.4	13.5	17.5	21.3		

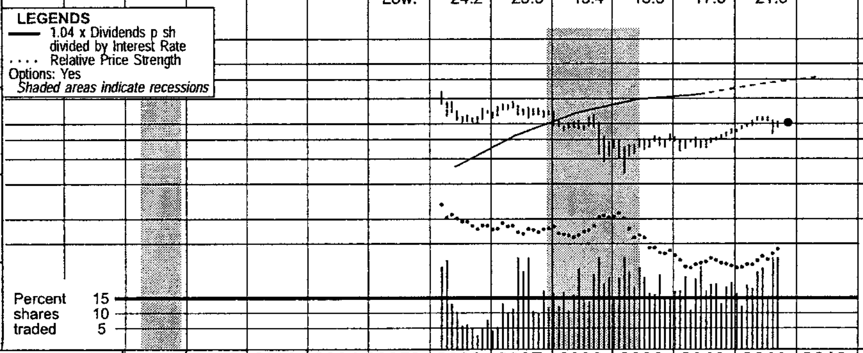
Target Price Range 2014 | 2015 | 2016

TIMELINESS **3** Lowered 8/19/11

SAFETY **3** Lowered 5/7/10

TECHNICAL **3** Lowered 9/9/11

BETA .75 (1.00 = Market)



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+25%)	*10%*
Low	20	(-20%)	*1%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	110	107	121
to Sell	77	89	104
Hld's(000)	66971	71103	70500

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.1	-4.8
3 yr.	14.7	25.0
5 yr.	19.5	16.6

On April 3, 2006, Portland General Electric's existing stock (which was owned by Enron) was canceled, and 62.5 million shares were issued to Enron's creditors or the Disputed Claims Reserve (DCR). The stock began trading on a when-issued basis that day, and regular trading began on April 10, 2006. Shares issued to the DCR were released over time to Enron's creditors until all of the remaining shares were released in June, 2007.

2001	2002	2003	2004	2005[G]	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
--	--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	***24.15***	***25.75***	Revenues per sh	***30.50***
--	--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	***5.00***	***5.25***	"Cash Flow" per sh	***6.00***
--	--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	***2.00***	***2.05***	Earnings per sh [A]	***2.25***
--	--	--	--	--	.68	.93	.97	1.01	1.04	***1.06***	***1.08***	Div'd Decl'd per sh [B] ■ †	***1.20***
--	--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	***4.50***	***4.05***	Cap'l Spending per sh	***3.75***
--	--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	***22.05***	***22.95***	Book Value per sh [C]	***25.75***
--	--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	***75.50***	***75.75***	Common Shs Outst'g [D]	***76.50***
--	--	--	--	--	23.4	11.9	16.3	14.4	12.0	***Bold figures are***	***Value Line***	Avg Ann'l P/E Ratio	***11.0***
--	--	--	--	--	1.26	.63	.98	.96	.76	***estimates***		Relative P/E Ratio	***.75***
--	--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%			Avg Ann'l Div'd Yield	***4.8%***
--	--	--	1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	***1825***	***1950***	Revenues ($mill)	***2325***
--	--	--	92.0	64.0	71.0	145.0	87.0	95.0	125.0	***150***	***155***	Net Profit ($mill)	***175***
--	--	--	37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	***25.0%***	***25.0%***	Income Tax Rate	***25.0%***
--	--	--	9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	***7.0%***	***3.0%***	AFUDC % to Net Profit	***3.0%***
--	--	--	41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	***50.5%***	***51.0%***	Long-Term Debt Ratio	***52.0%***
--	--	--	58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	***49.5%***	***49.0%***	Common Equity Ratio	***48.0%***
--	--	--	2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	***3360***	***3535***	Total Capital ($mill)	***4100***
--	--	--	2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	***4250***	***4315***	Net Plant ($mill)	***4325***
--	--	--	5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	***6.0%***	***6.0%***	Return on Total Cap'l	***5.5%***
--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	***9.0%***	***9.0%***	Return on Shr. Equity	***9.0%***
--	--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	***9.0%***	***9.0%***	Return on Com Equity [E]	***9.0%***
--	--	--	7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	***4.5%***	***4.5%***	Retained to Com Eq	***4.0%***
--	--	--	--	--	39%	40%	69%	76%	62%	***53%***	***52%***	All Div'ds to Net Prof	***52%***

CAPITAL STRUCTURE as of 6/30/11
Total Debt $1798.0 mill. **Due in 5 Yrs** $333.0 mill.
LT Debt $1798.0 mill. **LT Interest** $104.0 mill.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $10.0 mill.

Pension Assets-12/10 $473.0 mill.
Oblig. $550.0 mill.

Pfd Stock None

Common Stock 75,341,327 shs.
as of 7/29/11

MARKET CAP: $1.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.7	-3.3	-3.1
Avg. Indust. Use (MWH)	16255	14303	15109
Avg. Indust. Revs. per KWH (¢)	6.42	7.07	6.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) [F]	4031	3949	3582
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.8	+.7	+.5
Fixed Charge Cov. (%)	226	179	224

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	1.5%	*3.0%*
"Cash Flow"	--	-1.0%	*5.0%*
Earnings	--	7.5%	*7.5%*
Dividends	--	--	*3.0%*
Book Value	--	2.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	471.0	425.0	400.0	449.0	1745.0
2009	485.0	389.0	445.0	485.0	1804.0
2010	449.0	415.0	464.0	455.0	1783.0
2011	484.0	411.0	***455***	***475***	***1825***
2012	***525***	***450***	***475***	***500***	***1950***

Cal-endar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.44	.63	--	.32	1.39
2009	.47	.31	.43	.11	1.31
2010	.36	.32	.65	.34	1.66
2011	.92	.29	***.44***	***.35***	***2.00***
2012	***.70***	***.40***	***.55***	***.40***	***2.05***

Cal-endar	QUARTERLY DIVIDENDS PAID [B] ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.225	.225	.235	.235	.92
2008	.235	.245	.245	.245	.97
2009	.245	.245	.255	.255	1.00
2010	.255	.255	.26	.26	1.03
2011	.26	.26	.265	.265	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 825,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 45%; commercial, 34%; industrial, 12%; other, 9%. Generating sources: coal, 23%; gas, 21%; hydro, 9%; wind, 4%; purchased, 43%. Fuel costs: 46% of revenues. '10 reported depreciation rate: 3.9%. Has 2,700 employees. Chairman: Corbin A. McNeill, Jr. Chief Executive Officer and President: Jim Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric's earnings are likely to rise substantially this year. The utility is benefiting from a tariff increase that took effect at the start of 2011. The Public Utility Commission of Oregon raised PGE's rates by $65 million (3.9%). The rate order was based on a return of 10% on a common-equity ratio of 50%. Also, hydro conditions in early 2011 were favorable, helping to produce a first-quarter tally that was well above the norm for the period. Second-quarter profits were below our expectation, so we have trimmed our 2011 estimate by a nickel a share, to $2.00. Our revised estimate is still within the company's targeted range of $1.90-$2.05.

We expect little bottom-line improvement in 2012. We base our earnings forecast on normal hydro conditions. At least the service area's economy is showing moderate improvement, aided by a project that Intel is building.

For the time being, capital spending is declining. Last year, PGE completed the third phase of a 450-megawatt wind project, at a total cost of about $1 billion. No major construction is currently under way. In the next few months, however, the company will put forth requests for proposals for additional base-load, peaking, and renewable generating capacity. The outcome should be known in 2012. If PGE winds up building plants instead of entering into purchased-power agreements with other owners, this would raise its capital budget considerably and necessitate some financing, both debt and equity, beginning in 2013. Our capital spending estimates and projections include nothing for these potential projects. Separately, PGE is proposing to build a transmission line at a cost of $800 million-$1 billion. The company is looking for partners for the project, with an estimated in-service date in late 2016 or 2017.

This stock has an average dividend yield for a utility. With the quotation within our 2014-2016 Target Price Range, however, total return potential is unexciting. We believe there is a bit of takeover speculation in the share price, but we do not advise investors to purchase the stock in the hopes that the company will receive a buyout offer.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted EPS. '09 & '10 EPS don't add due to rounding. Next earnings report due late Feb. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '10: $7.22/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10.0%; earned on average com. eq., '10: 8.0%. Regulatory Climate: Below Average. (F) Summer peak in '09. (G) '05 per-share data are pro forma, based on shares outstanding when the stock began trading in '06.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	40

PPL CORPORATION NYSE-PPL

RECENT PRICE **26.97** | P/E RATIO **11.3** (Trailing: 10.9 / Median: 14.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **5.2%** | VALUE LINE

TIMELINESS 3 Raised 11/12/10

SAFETY 3 Lowered 11/28/08

TECHNICAL 2 Raised 7/22/11

BETA .65 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	23.1	31.2	20.0	22.2	27.1	33.7	37.3	54.6	55.2	34.4	33.1	28.7
Low:	9.2	15.5	13.0	15.8	19.9	25.5	27.8	34.4	26.8	24.3	23.8	24.1

2014-16 PROJECTIONS

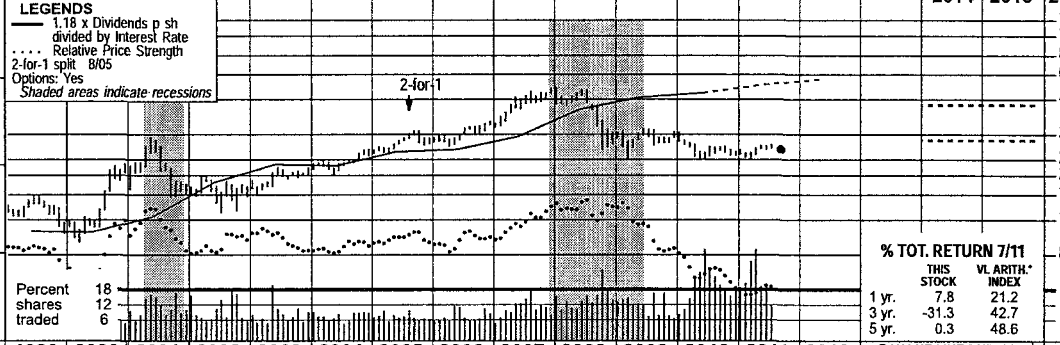
	Price	Gain	Ann'l Total Return
High	45	(+65%)	17%
Low	30	(+10%)	8%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	8	0	1	0	0
to Sell	1	0	0	0	3	0	0	0	0

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	243	223	231
to Sell	186	194	183
Hld's(000)	334842	314712	309906



Target Price Range 2014 | 2015 | 2016

120, 100, 80, 64, 48, 32, 24, 20, 16, 12, 8

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.8	21.2
3 yr.	-31.3	42.7
5 yr.	0.3	48.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
8.63	8.94	9.17	12.03	15.97	19.59	19.53	16.38	15.75	15.37	16.36	17.92	17.41	21.47	20.03	17.63	*19.20*	*20.70*	Revenues per sh	*20.50*
2.05	2.14	2.11	2.43	2.56	3.32	3.51	3.20	3.60	3.59	3.84	4.26	5.10	4.71	3.47	3.66	*3.95*	*4.35*	"Cash Flow" per sh	*4.75*
.97	1.03	.99	1.12	1.01	1.64	1.79	1.54	1.84	1.87	1.92	2.29	2.63	2.45	1.19	2.29	*2.40*	*2.55*	Earnings per sh A	*3.00*
.84	.84	.84	.67	.50	.53	.53	.72	.77	.82	.96	1.10	1.22	1.34	1.38	1.40	*1.40*	*1.40*	Div'd Decl'd per sh B ■	*1.70*
1.26	1.11	.93	.97	1.11	1.59	2.99	2.74	2.17	1.94	2.13	3.62	4.51	3.79	3.25	3.30	*4.85*	*6.40*	Cap'l Spending per sh	*5.50*
8.15	8.44	8.45	5.69	5.61	6.94	6.33	6.71	9.19	11.21	11.62	13.30	14.88	13.55	14.57	16.98	*19.20*	*20.40*	Book Value per sh C	*25.50*
318.81	325.33	332.50	314.82	287.39	290.08	293.16	331.47	354.72	378.14	380.15	385.04	373.27	374.58	377.18	483.39	*578.00*	*580.00*	Common Shs Outst'g D	*680.00*
10.8	11.4	10.8	10.9	13.4	8.9	12.4	11.1	10.6	12.5	15.1	14.1	17.3	17.6	25.7	11.9	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.0*
.72	.71	.62	.57	.76	.58	.64	.61	.60	.66	.80	.76	.92	1.06	1.71	.76	*estimates*		Relative P/E Ratio	*.85*
8.0%	7.1%	7.8%	5.5%	3.7%	3.6%	2.4%	4.2%	4.0%	3.5%	3.3%	3.4%	2.7%	3.1%	4.5%	5.1%			Avg Ann'l Div'd Yield	*4.5%*
						5725.0	5429.0	5587.0	5812.0	6219.0	6899.0	6498.0	8044.0	7556.0	8521.0	*11100*	*12000*	Revenues ($mill)	*13900*
						576.0	536.0	667.0	692.0	739.0	899.0	1031.0	940.0	465.0	1009.0	*1355*	*1495*	Net Profit ($mill)	*2030*
						29.7%	25.7%	27.1%	22.8%	14.0%	23.2%	20.7%	31.8%	21.8%	22.0%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						4.3%	3.4%	1.2%	.7%	--	--	--	.1%	.2%	.5%	*Nil*	*Nil*	AFUDC % to Net Profit	*Nil*
						64.8%	66.5%	71.1%	61.6%	57.5%	55.4%	54.1%	57.1%	55.2%	59.0%	*55.0%*	*52.0%*	Long-Term Debt Ratio	*43.0%*
						23.7%	25.1%	28.5%	37.9%	42.0%	42.2%	43.6%	40.5%	42.5%	39.8%	*44.0%*	*47.0%*	Common Equity Ratio	*56.0%*
						7845.0	8868.0	11455	11171	10513	12151	12747	12529	12940	20621	*25250*	*25150*	Total Capital ($mill)	*30800*
						6135.0	9566.0	10446	11209	10916	12069	12605	12416	13174	20858	*27475*	*30150*	Net Plant ($mill)	*38600*
						9.6%	8.8%	7.6%	8.4%	9.3%	9.3%	9.8%	9.2%	5.0%	6.1%	*6.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
						20.8%	18.1%	20.2%	16.1%	16.5%	16.6%	17.6%	17.5%	8.0%	11.9%	*12.0%*	*12.5%*	Return on Shr. Equity	*11.5%*
						28.2%	21.1%	19.6%	16.3%	16.7%	17.3%	18.2%	18.2%	8.1%	12.0%	*12.0%*	*12.5%*	Return on Com Equity E	*11.5%*
						20.2%	12.4%	11.7%	9.3%	8.8%	9.3%	10.0%	8.5%	NMF	5.2%	*5.5%*	*5.5%*	Retained to Com Eq	*5.0%*
						35%	49%	43%	43%	47%	47%	46%	54%	115%	58%	*56%*	*55%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $13630 mill. **Due in 5 Yrs** $4130.0 mill.
LT Debt $12247 mill. **LT Interest** $612.0 mill.
Incl. 23 mill. units 7.75%, $25 liq. value; 82,000 units 8.23%, $1000 face value; 23 mill. units 4.625%, $50 stated value, conv. into com. in 2013.
(LT interest earned: 3.7x)
Leases, Uncapitalized Annual rentals $122.0 mill.
Pension Assets-12/10 $5.34 bill. **Oblig.** $6.85 bill.
Pfd Stock $250.0 mill. **Pfd Div'd** $16.0 mill.
2,500,000 shs. 6.25%, $100 liq. preference, redeemable after 4/6/11.
Common Stock 577,151,364 shs. **as of 4/29/11**
MARKET CAP: $16 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	+.3	-3.5	+15.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	7316	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.3	+22.5
Fixed Charge Cov. (%)	367	222	304

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	2.0%	4.5%	*.5%*
"Cash Flow"	3.5%	1.5%	*3.0%*
Earnings	4.5%	1.0%	*7.0%*
Dividends	9.5%	10.0%	*3.5%*
Book Value	9.5%	7.0%	*9.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1526	1024	2981	2513	8044.0
2009	2351	1673	1805	1727	7556.0
2010	3006	1473	2179	1863	8521.0
2011	2910	2489	*3051*	*2650*	*11100*
2012	*3400*	*2600*	*3200*	*2800*	*12000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.65	.50	.55	.74	2.45
2009	.64	.07	.12	.37	1.19
2010	.74	.22	.62	.69	2.29
2011	.82	.35	*.60*	*.63*	*2.40*
2012	*.80*	*.45*	*.65*	*.65*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.275	.305	.305	.305	1.19
2008	.305	.335	.335	.335	1.31
2009	.335	.345	.345	.345	1.37
2010	.345	.35	.35	.35	1.40
2011	.35	.35	.35		

BUSINESS: PPL Corporation (formerly PP&L Resources, Inc.) is a holding company for PPL Electric Utilities (formerly Pennsylvania Power & Light Company), which distributes electricity to 1.4 mill. customers in eastern & central PA. Acq'd Kentucky Utilities and Louisville Gas and Electric (1.2 mill. customers) 11/10. Has subsidiaries in power generation & marketing, electricity distribution in U.K. (7.6 mill. customers). Sold gas distribution subsidiary in '08. Electric rev. breakdown & generating sources not provided. Fuel costs: 44% of revs. '10 reported depr. rates: 2.3%-3.3%. Has 13,800 employees. Chairman & CEO: James H. Miller. President & COO: William H. Spence. Inc.: PA. Address: Two North Ninth St., Allentown, PA 18101-1179. Tel.: 800-345-3085. Internet: www.pplweb.com.

Predicting PPL Corporation's earnings is harder than usual this year. Just since November of 2010, the company has greatly expanded its regulated utility operations by buying two utilities in Kentucky and one in the United Kingdom. PPL issued a lot of stock in these deals, resulting in a big jump in average shares outstanding. Also, the company is incurring some merger-related expenses, which we *include* in our earnings presentation. Generally, the company's utility operations are performing well, but PPL Electric Utilities in Pennsylvania continues to feel the effects of regulatory lag, despite a rate hike earlier this year. On the other hand, the nonregulated energy-supply business is dealing with low power prices, rising coal costs, and unplanned nuclear outages that will reduce net profit by an estimated $60 million-$65 million this year. Finally, ongoing earnings are affected by mark-to-market accounting gains or losses. These hurt share net by $0.27 in 2010 and helped by a cent in the first half of 2011. We cut our 2011 estimate by $0.15 a share, largely because second-quarter profits fell short of our estimate.

We expect improved earnings in 2012. A full year's income from the U.K. acquisition will help. Also, we assume no nuclear issues beyond the normal expenses associated with the scheduled refueling outage. Our estimate of $2.55 a share would be PPL's best tally since 2007.

The two Kentucky utilities are asking the state commission to approve an expected $2.5 billion in environmental spending for their coal-fired facilities. This spending is needed for compliance with new EPA rules. A decision is expected in late 2011. The utilities would recover these expenditures every two months via a rider on customers' bills. The utilities will earn a return on equity of 10.63% until this spending is rolled into base rates.

PPL stock offers an above-average yield. The board of directors didn't boost the dividend this year, and we forecast no increase in 2012. Even so, we project that dividend growth will resume by the 2014-2016 period. Combined with the rise in earnings that we project over that time, this equity offers better total return potential than the average utility issue.

Paul E. Debbas, CFA *August 26, 2011*

(A) Diluted EPS. Excl. nonrec. losses: '07, 12¢; '10, 8¢; gains (losses) on disc. ops.: '05, (12¢); '07, 19¢; '08, 3¢; '09, (10¢); '10, (4¢). '08 & '09 EPS don't add due to rounding, '10 due to chg. in shs. Next earnings report due early Nov. (B) Div'ds histor. paid in early Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. (C) Incl. intang. In '10: $8.01/sh. (D) In mill., adj. for split. (E) Rate base: Fair val. Rate all'd on com. eq. in PA in '08: none spec.; in KY in '10: 9.75%-10.75%; earned on avg. com. eq., '10: 14.0%. Regulat. Climate: Avg. (F) Summer peak in '08.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	60

TECO ENERGY, INC. NYSE-TE

RECENT PRICE	17.48	P/E RATIO	12.4 (Trailing: 15.6; Median: 15.0)	RELATIVE P/E RATIO	0.91	DIV'D YLD	5.0%	VALUE LINE

TIMELINESS 2 Raised 8/26/11
SAFETY 3 Lowered 3/7/03
TECHNICAL 3 Lowered 7/8/11
BETA .85 (1.00 = Market)

High:	33.2	33.0	29.0	17.0	15.5	19.3	17.7	18.6	22.0	16.7	18.1	19.7		
Low:	17.3	24.8	10.0	9.5	11.3	14.9	14.4	14.8	10.5	8.4	14.5	15.8		

Target Price Range
2014 | 2015 | 2016

2014-16 PROJECTIONS

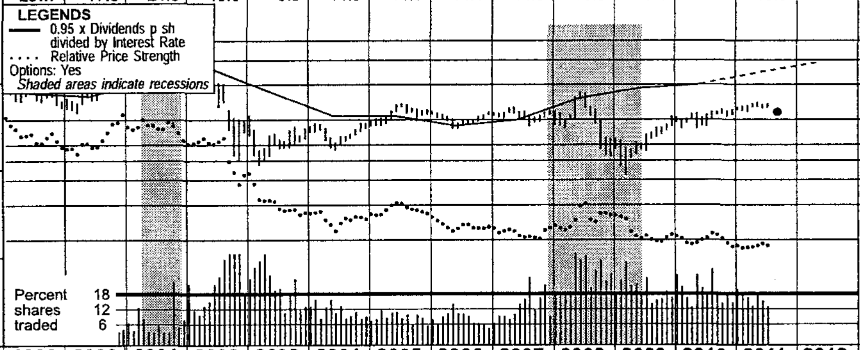
	Price	Gain	Ann'l Total Return
High	25	(+45%)	14%
Low	18	(+5%)	7%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	1	0	0	0	0	2
to Sell	0	0	2	1	0	0	0	0	2

Institutional Decisions

	3Q2010	4Q2010	1Q2011
to Buy	160	141	117
to Sell	131	156	181
Hld's(000)	115966	118085	113977



40
32
24
16
12
10
8
6
4

% TOT. RETURN 7/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	21.2
3 yr.	17.9	42.7
5 yr.	50.4	48.6

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
11.90	12.53	14.23	14.83	15.01	18.17	18.97	15.22	14.59	13.37	14.46	16.46	16.77	15.85	15.48	16.23	*15.75*	*16.15*	Revenues per sh	*18.25*
3.08	3.28	3.34	3.25	3.28	4.11	4.31	3.20	1.96	2.14	2.37	2.51	2.51	2.01	2.35	2.59	*2.80*	*3.05*	"Cash Flow" per sh	*3.50*
1.60	1.71	1.61	1.52	1.53	1.97	2.24	1.95	d.08	.71	1.00	1.17	1.27	.77	1.00	1.13	*1.30*	*1.45*	Earnings per sh A	*1.75*
1.05	1.11	1.17	1.23	1.29	1.33	1.37	1.41	.93	.76	.76	.76	.78	.80	.80	.82	*.85*	*.89*	Div'd Decl'd per sh B ■	*1.05*
3.70	2.28	1.62	2.24	3.23	5.45	6.92	6.06	3.14	1.37	1.42	2.18	2.34	2.77	2.99	2.28	*2.05*	*2.15*	Cap'l Spending per sh	*2.00*
9.98	10.73	11.04	11.42	10.73	11.93	14.12	14.86	8.93	6.43	7.65	8.25	9.56	9.43	9.75	10.10	*10.55*	*11.15*	Book Value per sh C	*13.25*
116.96	117.60	130.90	132.00	132.10	126.30	139.60	175.80	187.80	199.70	208.20	209.50	210.90	212.90	213.90	214.90	*216.00*	*217.00*	Common Shs Outst'g D	*220.00*
13.8	14.3	15.4	17.8	14.2	11.9	12.9	11.0	--	19.3	17.1	13.8	13.3	21.2	12.6	14.6	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.92	.90	.89	.93	.81	.77	.66	.60	--	1.02	.91	.75	.71	1.28	.84	.93	*Value Line*		Relative P/E Ratio	*.85*
4.7%	4.5%	4.7%	4.5%	5.9%	5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	4.6%	4.9%	6.3%	4.9%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/11
Total Debt $3148.6 mill. **Due in 5 Yrs** $924.1 mill.
LT Debt $3070.3 mill. **LT Interest** $198.0 mill.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $17.3 mill.

Pension Assets-12/10 $479.7 mill.
Oblig. $610.3 mill.

Pfd Stock None

Common Stock 214,936,829 shs.
as of 4/28/11
MARKET CAP: $3.8 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
2648.6	2675.8	2740.0	2669.1	3010.1	3448.1	3536.1	3375.3	3310.5	3487.9	*3400*	*3500*	Revenues ($mill)	*4000*
303.7	298.2	d14.7	137.4	211.0	244.4	265.8	162.4	213.9	242.9	*285*	*325*	Net Profit ($mill)	*385*
--	--	--	38.5%	45.1%	40.4%	40.7%	36.8%	31.6%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.0%	4.4%	--	.7%	.0%	1.6%	2.3%	5.4%	6.5%	1.2%	*1.0%*	*3.0%*	AFUDC % to Net Profit	*1.0%*
48.3%	50.5%	72.4%	75.1%	70.0%	65.0%	61.0%	61.5%	60.6%	59.2%	*51.0%*	*56.0%*	Long-Term Debt Ratio	*52.5%*
51.7%	39.7%	27.6%	24.9%	30.0%	35.0%	39.0%	38.5%	39.4%	40.8%	*49.0%*	*44.0%*	Common Equity Ratio	*47.5%*
3814.1	6585.1	6070.3	5163.9	5300.9	4941.6	5175.4	5214.3	5287.0	5317.8	*4635*	*5515*	Total Capital ($mill)	*6100*
4838.3	5464.0	5679.0	4657.9	4566.9	4766.9	4888.2	5221.3	5544.1	5841.0	*5955*	*6085*	Net Plant ($mill)	*6225*
9.7%	5.7%	2.1%	5.6%	6.5%	7.3%	7.3%	5.1%	6.0%	6.4%	*8.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
15.4%	9.1%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	*12.5%*	*13.5%*	Return on Shr. Equity	*13.0%*
15.4%	9.9%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	*12.5%*	*13.5%*	Return on Com Equity E	*13.0%*
6.1%	3.2%	NMF	NMF	3.3%	5.0%	5.1%	NMF	2.1%	3.1%	*4.5%*	*5.5%*	Retained to Com Eq	*5.5%*
61%	72%	NMF	106%	75%	65%	61%	104%	80%	72%	*65%*	*60%*	All Div'ds to Net Prof	*60%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.8	-1.1	+2.3
Avg. Indust. Use (Mw)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.04	9.63	9.35
Capacity at Peak (Mw)	4477	4719	4684
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	+.1	-.1	+.6
Fixed Charge Cov. (%)	166	199	270

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	2.5%	2.5%
"Cash Flow"	-4.0%	1.5%	7.0%
Earnings	-5.5%	12.0%	10.5%
Dividends	-4.5%	-.5%	4.5%
Book Value	-1.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	791.7	887.2	926.1	770.3	3375.3
2009	824.0	825.2	896.3	765.0	3310.5
2010	912.3	898.8	901.8	775.0	3487.9
2011	796.1	885.7	*918.2*	*800*	*3400*
2012	*800*	*900*	*950*	*850*	*3500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.15	.24	.27	.10	.77
2009	.16	.29	.30	.25	1.00
2010	.26	.35	.35	.17	1.13
2011	.24	.36	*.37*	*.33*	*1.30*
2012	*.35*	*.35*	*.40*	*.35*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.19	.195	.195	.195	.78
2008	.195	.20	.20	.20	.80
2009	.20	.20	.20	.20	.80
2010	.20	.205	.205	.205	.82
2011	.205	.215	.215		

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves 672,000 customers in west central Florida, and Peoples Gas (acquired 6/97), which serves 336,000 customers in Florida. TECO also mines coal and has generation investments in Guatemala. Sold TECO Transport 12/07. Electric revenue breakdown: residential, 50%; commercial, 30%; industrial, 9%; other, 11%. Generating sources: coal, 53%; gas, 38%; purchased, 9%. Fuel costs: 35% of revenues. '10 reported deprec. rate (utility): 3.6%. Has 4,100 employees. Chairman: Sherrill W. Hudson. President & CEO: John B. Ramil. Incorporated: Florida. Address: TECO Plaza, 702 N. Franklin Street, Tampa, Florida 33602. Telephone: 813-228-1111. Internet: www.tecoenergy.com.

We estimate that TECO Energy's earnings will increase this year. In 2010, the company incurred $0.16 a share of charges for the early retirement of debt. There were no such charges in the first half of 2011, and we expect none in the second half. The refinancings and repayments of debt have lowered TECO's interest expense. Tampa Electric and Peoples Gas are performing well and are likely to earn their allowed returns on equity this year. In fact, the utilities' customer counts have risen for seven consecutive quarters, which suggests that the service area is recovering (albeit slowly) from the housing crisis in Florida. All told, our 2011 earnings estimate is within management's targeted range of $1.25-$1.40 a share.

TECO Coal is experiencing some positive and negative trends. On the positive side, contracted prices are rising, and the proportion of the company's sales that is for higher-priced specialty coal is increasing. Realized prices should get a further boost next year, after a contract for 600,000 tons, which is well below the current market level, expires. This production has been sold at prices that are well above the price in that contract. On the negative side, costs are up, as well, and volume is below management's previous expectation for the year. TECO Coal now expects sales of 8.2 million-8.5 million tons this year, compared with 8.5 million-9.0 million previously. The volume shortfall is due to delays in surface mine permitting and a shortage of contract minors, and the higher price of oil is causing the cost of oil-based equipment, such as tires, to climb. When all is said and done, we believe the pluses will exceed the minuses, and TECO Coal's contribution to the parent's bottom line will increase this year and next.

Earnings should advance solidly in 2012. The aforementioned repricing of an old contract at TECO Coal should be the key factor. We look for modest growth from the utilities, too. Our profit forecast remains at $1.45 a share.

Timely TECO stock offers a dividend yield and 2014-2016 total return potential that are somewhat above the norm for utilities. Moderate dividend growth should occur through the middle of the decade.

Paul E. Debbas, CFA *August 26, 2011*

(A) Dil. earnings. Excl. nonrec. gain (losses): '97, (6¢); '99, (11¢); '03, ($4.97); '07, 63¢; '10, (2¢) net; gains (loss) on discont. ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢. '08 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds paid in late Feb., May, Aug. & Nov. ■ Div'd reinvestment plan avail. (C) Incl. def'd chgs. In '10: $2.77/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09 (elec.): 10.25%-12.25%; in '09 (gas): 9.75%-11.75%; earned on avg. com. eq., '10: 11.4%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	65

WESTAR ENERGY NYSE-WR

RECENT PRICE	25.54	P/E RATIO	14.8 (Trailing: 15.0 Median: 14.0)	RELATIVE P/E RATIO	1.10	DIV'D YLD	5.1%	VALUE LINE

TIMELINESS 3 Lowered 3/11/11

SAFETY 2 Raised 4/1/05

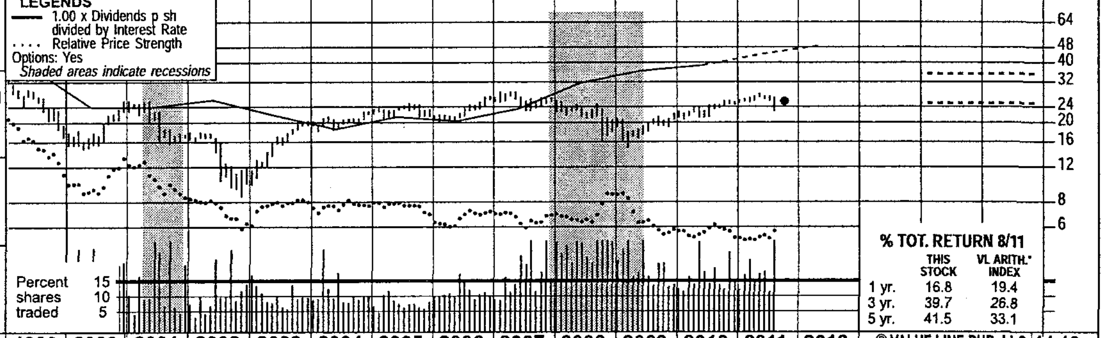
TECHNICAL 3 Lowered 9/9/11

BETA .75 (1.00 = Market)

High:	25.9	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9	22.3	25.9	28.0
Low:	14.7	15.6	8.5	9.8	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+35%)	12%
Low	25	(Nil)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	3	0	3	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	121	107	98
to Sell	88	98	107
Hld's(000)	81435	81083	77664

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.8	19.4
3 yr.	39.7	26.8
5 yr.	41.5	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
25.01	31.67	32.90	30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	*18.15*	*18.60*	Revenues per sh	*20.30*
5.17	5.52	3.47	6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	*4.05*	*4.30*	"Cash Flow" per sh	*4.90*
2.71	2.60	d.46	2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	*1.68*	*1.90*	Earnings per sh A	*2.40*
2.03	2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	*1.28*	*1.32*	Div'd Decl'd per sh B■†	*1.44*
3.77	3.09	3.22	2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	*5.75*	*5.85*	Cap'l Spending per sh	*7.05*
24.71	25.14	30.79	29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	*21.60*	*22.10*	Book Value per sh C	*23.45*
62.86	64.63	65.41	65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	*117.00*	*120.00*	Common Shs Outst'g E	*128.00*
11.7	11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.5*
.78	.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.84	*estimates*		Relative P/E Ratio	*.85*
6.4%	6.8%	6.3%	5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%			Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3259.0 mill. **Due in 5 Yrs** $857.5 mill.
LT Debt $2761.0 mill. **LT Interest** $165.0 mill.
(LT interest earned: 2.6x)

Pension Assets-12/10 $432 mill. **Oblig.** $747 mill.

Pfd Stock $21.4 mill. **Pfd Div'd** $1.0 mill.
121,613 shs. 4 1/2%, callable 108; 54,970 shs. 4 1/4%, callable 101.50; 37,780 shs. 5%, callable 102. All cum. $100 par.

Common Stock 115,812,605 shs. as of 7/26/11
MARKET CAP: $3.0 billion (Mid Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
2186.3	1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	*2125*	*2230*	Revenues ($mill)	*2600*
d40.0	72.0	108.1	100.1	134.9	165.3	168.4	136.8	141.3	203.9	*195*	*225*	Net Profit ($mill)	*305*
NMF	53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
--	--	5.0%	--	--	--	10.4%	--	10.4%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
61.8%	71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	*52.5%*	*53.0%*	Long-Term Debt Ratio	*54.0%*
37.7%	22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	49.7%	46.1%	46.4%	*47.5%*	*47.0%*	Common Equity Ratio	*46.0%*
4822.4	4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4400.1	4866.8	5180.8	*5325*	*5650*	Total Capital ($mill)	*6500*
4042.9	3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	*6300*	*6750*	Net Plant ($mill)	*7800*
1.5%	4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	4.2%	4.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.5%*
NMF	5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	6.2%	6.2%	8.1%	*7.5%*	*8.5%*	Return on Shr. Equity	*10.0%*
NMF	7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	6.3%	8.2%	*7.5%*	*8.5%*	Return on Com Equity D	*10.0%*
NMF	NMF	4.9%	3.2%	4.3%	5.5%	4.3%	1.2%	.8%	2.8%	*2.0%*	*2.5%*	Retained to Com Eq	*4.0%*
NMF	120%	53%	56%	55%	49%	53%	80%	87%	65%	*76%*	*70%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.0	-2.0	+6.2
Avg. Indust. Use (MWH)	5769	5145	5468
Avg. Indust. Revs. per KWH (¢)	5.06	5.67	5.82
Capacity at Peak (Mw)	6508	6807	6756
Peak Load, Summer (Mw)	4754	4545	5485
Annual Load Factor (%)	55.0	54.5	55.0
% Change Customers (yr-end)	+.7	+.9	+.3
Fixed Charge Cov. (%)	263	226	267

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	-6.0%	-1.0%	2.5%
"Cash Flow"	-6.0%	1.5%	5.0%
Earnings	--	1.0%	8.5%
Dividends	-4.5%	7.0%	3.0%
Book Value	-3.0%	6.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	406.8	451.2	574.9	406.1	1839.0
2009	421.8	467.8	528.5	440.1	1858.2
2010	459.8	495.2	644.4	456.8	2056.2
2011	481.7	524.9	*650*	*468.4*	*2125*
2012	*500*	*540*	*680*	*510*	*2230*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.06	.81	.21	1.31
2009	.10	.35	.73	.10	1.28
2010	.27	.47	1.01	.04	1.80
2011	.27	.38	*.96*	*.07*	*1.68*
2012	*.32*	*.48*	*1.00*	*.10*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.25	.27	.27	.27	1.06
2008	.27	.29	.29	.29	1.14
2009	.29	.30	.30	.30	1.19
2010	.30	.31	.31	.31	1.23
2011	.31	.32	.32		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 687,000 customers in Kansas. Electric revenue sources: residential and rural, 43%; commercial, 37%; industrial, 20%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2010 depreciation rate: 4.6%. Estimated plant age: 13 years. Fuels: coal, 51%; nuclear, 8%; gas, 41%. Has 2,409 employees. BlackRock, Inc. owns 6.3% of common; off. & dir., less than 1% (4/11 proxy). Chairman: Charles Q. Chandler IV. Chief Executive Officer: Mark A. Ruelle. Inc.: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Shares of Westar Energy have rebounded in recent weeks, following a mid-summer selloff. The company reported mixed results for the second quarter. The top line increased at a moderate clip, thanks to higher retail revenue. However, this was more than offset by greater operating expenses, and share net came in somewhat below the prior-year tally.

Mixed performance ought to continue for the remainder of the year. Revenue comparisons should remain favorable in the coming quarters. The economy in Kansas will likely continue to fare better than the nation's. With the state's attractive business climate, unemployment there should remain below the national average, and most industrial sectors should show further improvement. That said, operating costs will probably continue to weigh on the bottom line. Overall, we project higher revenue, but a bottom-line decline for full-year 2011. Share net should rebound in 2012, assuming solid revenue growth and greater control of operating costs.

We anticipate further investment in operations going forward. Westar continues to make progress with its 345-kilovolt transmission line from Wichita to Oklahoma. This project is trending favorable with respect to schedule and budget, and will likely be completed by mid-2012. The company continues to move forward with the Prairie Wind joint venture, and invest in environmental controls, too.

Westar is requesting higher rates. The company filed in late August with the Kansas Corporation Commission (KCC), seeking to increase base prices by about 5.85%. This would add about $91 million to revenue, on an annual basis. Westar cited higher operating and maintenance expenses, and the increased cost of complying with federal regulatory requirements, as reasons for the request.

This stock is neutrally ranked for Timeliness. We anticipate higher revenues and share earnings for the company by 2014-2016. Moreover, Westar earns good marks for Safety, Price Stability, and Earnings Predictability. From the present quotation, this issue has decent risk-adjusted total return potential. Income-oriented accounts should find this stock's healthy dividend yield attractive.

Michael Napoli, CFA *September 23, 2011*

(A) EPS diluted from 2010 onward. Excl. nonrecur gains (losses): '96, ($0.19); '97, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢, '02, ($12.06); '03, 77¢; '08, 39¢. Totals may not sum due to rounding. Next egs. rep't due late October. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. regulatory assets. In 2010: $7.68/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '09: 10.4%; earned on avg. com. eq., '10: 8.7%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	75

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE 31.02 | P/E RATIO 14.2 (Trailing: 14.6 / Median: 14.0) | RELATIVE P/E RATIO 1.06 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 2 Raised 8/6/10

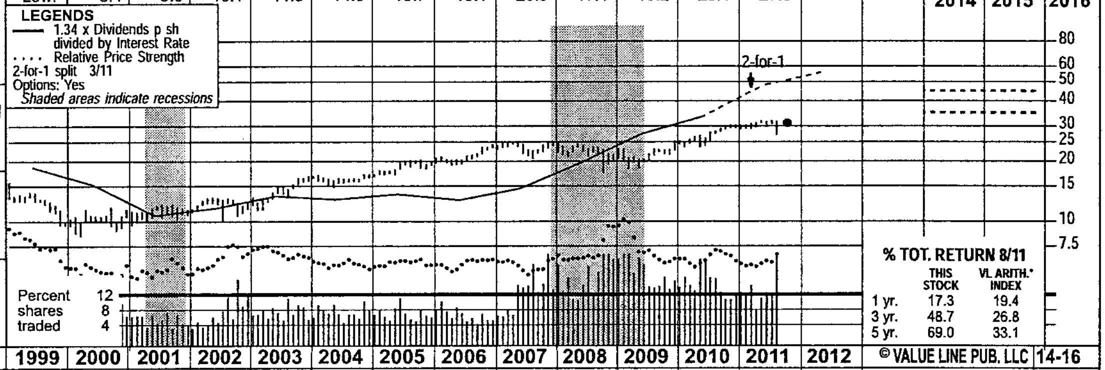
SAFETY 2 Lowered 7/11/97

TECHNICAL 3 Lowered 9/16/11

BETA .65 (1.00 = Market)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
High:	11.8	12.3	13.2	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	32.1
Low:	8.4	9.6	10.1	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0

Target Price Range 2014 | 2015 | 2016



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+45%)	13%
Low	35	(+15%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	5	2	0	1	3	5	0	8	0
to Sell	3	2	0	1	5	5	0	8	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	175	150	171
to Sell	147	171	155
Hld's(000)	160351	161929	160735

% TOT. RETURN 8/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.3	19.4
3 yr.	48.7	26.8
5 yr.	69.0	33.1

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
7.99	7.94	7.93	8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.40	19.30	Revenues per sh	23.50
2.14	2.13	1.48	2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.65	3.30	"Cash Flow" per sh	5.00
1.07	.99	.27	.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.15	2.25	Earnings per sh A	2.75
.73	.75	.77	.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	1.14	Div'd Decl'd per sh B ■ †	1.65
1.25	1.77	1.56	1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	4.35	3.10	Cap'l Spending per sh	3.00
8.44	8.71	8.25	8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.05	17.60	Book Value per sh C	19.75
221.64	223.36	225.73	231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	232.00	228.00	Common Shs Outst'g D	224.00
13.1	14.3	47.3	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	Bold figures are		Avg Ann'l P/E Ratio	14.5
.88	.90	2.73	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.90	Value Line		Relative P/E Ratio	.95
5.2%	5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	estimates		Avg Ann'l Div'd Yield	4.2%

CAPITAL STRUCTURE as of 6/30/11
Total Debt $4907.6 mill. **Due in 5 Yrs** $1729.0 mill.
LT Debt $4334.6 mill. **LT Interest** $244.9 mill.
Incl. $132.4 mill. capitalized leases.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $22.8 mill.
Pension Assets-12/10 $1.06 bill.
Oblig. $1.22 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.

Common Stock 233,739,777 shs.
MARKET CAP: $7.2 billion (Large Cap)

2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012		14-16
3928.5	3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	4500	4400	Revenues ($mill)	5250
218.8	270.8	269.2	221.2	304.8	313.7	337.7	359.8	378.4	455.6	510	520	Net Profit ($mill)	625
40.9%	37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	34.5%	35.0%	Income Tax Rate	34.0%
6.9%	4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	12.0%	10.0%	AFUDC % to Net Profit	8.0%
62.2%	59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	54.0%	54.0%	Long-Term Debt Ratio	53.5%
37.2%	39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	46.0%	45.5%	Common Equity Ratio	46.5%
5523.8	5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	8640	8800	Total Capital ($mill)	9475
4188.0	4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	10275	10750	Net Plant ($mill)	11225
5.8%	7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	7.5%	7.5%	Return on Total Cap'l	8.0%
10.5%	12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	13.0%	13.0%	Return on Shr. Equity	14.0%
10.6%	12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	13.0%	13.0%	Return on Com Equity E	14.0%
6.0%	8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	6.5%	6.5%	Retained to Com Eq	6.0%
43%	35%	35%	45%	34%	35%	35%	35%	42%	41%	48%	50%	All Div'ds to Net Prof	59%

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-2.2	-8.1	+6.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.05	6.57	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5740	5812	5908
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	+.2	+.3
Fixed Charge Cov. (%)	270	281	312

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	5.5%	2.5%	4.5%
"Cash Flow"	3.5%	2.5%	8.0%
Earnings	8.0%	8.5%	8.5%
Dividends	-1.0%	10.0%	16.0%
Book Value	6.0%	7.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	1431.8	946.1	852.5	1200.6	4431.0
2009	1396.2	842.5	821.9	1067.3	4127.9
2010	1248.6	890.9	973.2	1089.8	4202.5
2011	1328.7	991.7	979.6	1200	4500
2012	1325	975	925	1175	4400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.52	.25	.33	.42	1.52
2009	.60	.27	.25	.48	1.60
2010	.55	.37	.47	.53	1.92
2011	.72	.41	.47	.55	2.15
2012	.75	.42	.50	.58	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.125	.125	.125	.125	.50
2008	.135	.135	.135	.135	.54
2009	.169	.169	.169	.169	.68
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26		

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 38%; small commercial & industrial, 31%; large commercial & industrial, 23%; other, 8%. Generating sources: coal, 54%; gas, 9%; hydro, 1%; wind, 1%; purchased, 35%. Fuel costs: 44% of revs. '10 reported deprec. rate (utility): 2.8%. Has 4,600 employees. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy is awaiting a decision from the state commission about the company's regulatory proposal. Typically, the utility would have filed a general rate case in May, with new tariffs taking effect the following January. But, in order to reduce rate pressure on its customers, the company made an alternative proposal. Instead of filing a general rate case, Wisconsin Energy proposed that it be allowed to suspend $140.1 million of regulatory amortization in 2012. This would help lift earnings next year without a base rate hike. The utility would file a general rate case in 2012, with new tariffs taking effect in 2013. However, if the commission rejects this idea, the company would file a general rate case. Wisconsin Energy would request electric, gas, and steam increases of $170.6 million, $6.0 million, and $3.6 million, respectively. The commission's decision is expected next month.

Earnings are likely to rise in 2011 and 2012. This year, Wisconsin Energy is benefiting from the income from a coal-fired facility that began commercial operation in early 2011. Hot weather is another plus, and has helped offset the effect of the sputtering economy on electric demand. The beginning of a $300 million stock buyback program should help, too. We assume the adoption of Wisconsin Energy's aforementioned regulatory proposal in our 2012 profit forecast.

A general rate case is pending in Michigan. The utility is seeking an increase of $14.9 million, based on a 10.4% return on equity. The company expects to self-implement a $7.7 million hike in January. The final order is due in July.

Two renewable-energy projects are being built. The company is spending $361 million to add 162 megawatts of wind capacity. This project should be completed by yearend. A 50-mw biomass plant is expected to be in service by the end of 2013 at a projected cost of $255 million.

This timely stock is suitable for utility investors who are focused on dividend growth. The payout ratio is now low, by utility standards, but the company wants to raise it to 60%. Accordingly, hefty dividend boosts are likely to occur. This should produce an above-average (for a utility) total return through mid-decade.

Paul E. Debbas, CFA *September 23, 2011*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 5¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '10: $6.55/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates allowed on com. eq. in '10: 10.4%-10.5%; earned on avg. com. eq., '09: 10.8%. Regulatory Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	90

ATTACHMENT B

ZACKS INVESTMENT RESEARCH

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

AMEREN CORP (NYSE)

ZACKS RANK: 3 - HOLD

AEE 32.74 ▲0.45 (1.39%) Vol. 1,307,632 15:07 ET

Ameren Corporation companies provide energy services customers in Missouri and Illinois. AmerenUE, one of its subsidiaries, is the one of the largest electric utilities in Missouri and distributors of natural gas. AmerenCIPS, another subsidiary, is both an electric and natural gas utility and serves one of the largest geographic areas of Illinois-based utility companies. (Company Press Release)

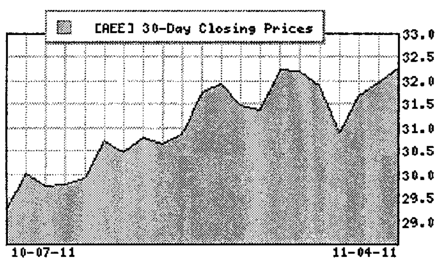
General Information

AMEREN CORP
1901 CHOUTEAU AVE
ST LOUIS, MO 63103
Phone: 314-621-3222
Fax: 314-621-2888
Web: http://www.ameren.com
Email: invest@ameren.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/21/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.29
52 Week High	33.49
52 Week Low	25.55
Beta	0.63
20 Day Moving Average	1,847,078.25
Target Price Consensus	28.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	10.39	4 Week	1.78
12 Week	17.85	12 Week	10.85
YTD	14.54	YTD	14.95

Share Information		Dividend Information	
Shares Outstanding (millions)	241.67	Dividend Yield	4.77%
		Annual Dividend	$1.54
Market Capitalization (millions)	7,803.40	Payout Ratio	0.59
Short Ratio	2.15	Change in Payout Ratio	-0.09
Last Split Date	N/A	Last Dividend Payout / Amount	09/06/2011 / $0.38

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.32	Current (1=Strong Buy, 5=Strong Sell)	3.20
Current Year EPS Consensus Estimate	2.55	30 Days Ago	3.20
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	3.20
Next EPS Report Date	02/21/2012	90 Days Ago	3.22

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.66	vs. Previous Year	12.14%	vs. Previous Year	0.62%
Trailing 12 Months:	12.28	vs. Previous Quarter	166.10%	vs. Previous Quarter:	27.34%
PEG Ratio	3.17				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.96	09/30/11	8.05	09/30/11	2.74

Price/Cash Flow	5.10	06/30/11	7.54	06/30/11	2.54
Price / Sales	1.02	03/31/11	7.86	03/31/11	2.65
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.45	09/30/11	1.05	09/30/11	8.37
06/30/11	1.51	06/30/11	1.13	06/30/11	7.79
03/31/11	1.48	03/31/11	1.17	03/31/11	8.28
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	11.45	09/30/11	11.45	09/30/11	33.73
06/30/11	5.23	06/30/11	5.23	06/30/11	32.94
03/31/11	5.47	03/31/11	5.47	03/31/11	32.76
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.52	09/30/11	0.82	09/30/11	45.04
06/30/11	7.47	06/30/11	0.89	06/30/11	47.04
03/31/11	7.32	03/31/11	0.90	03/31/11	47.48

ZACKS
INVESTMENT RESEARCH
Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

AMERICAN ELEC PWR INC (NYSE)

ZACKS RANK: 3 - HOLD

AEP 39.74 ▲0.04 (0.10%) Vol. 2,300,064 15:30 ET

American Electric Power is a public utility holding company which owns,directly or indirectly, all of the outstanding common stock of its domesticelectric utility subsidiaries and varying percentages of other subsidiaries. Substantially all of the operating revenues of AEP and its subsidiaries are derived from the furnishing of electric service. The Company's operations are divided into three business segments: Wholesale, Energy Delivery and Other.

General Information

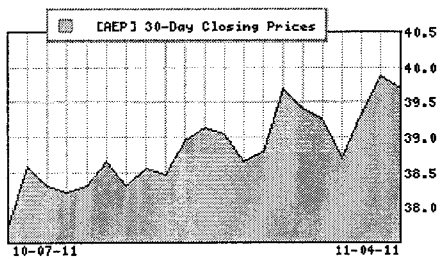
AMER ELEC PWR
1 RIVERSIDE PLAZA
COLUMBUS, OH 43215
Phone: 614-716-1000
Fax: 614-223-1823
Web: http://www.aep.com
Email: klkozero@aep.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	01/27/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	39.70
52 Week High	40.08
52 Week Low	33.09
Beta	0.51
20 Day Moving Average	3,840,518.00
Target Price Consensus	40.93



% Price Change

4 Week	5.19
12 Week	11.02
YTD	10.34

% Price Change Relative to S&P 500

4 Week	-3.01
12 Week	4.43
YTD	10.73

Share Information

Shares Outstanding (millions)	482.27
Market Capitalization (millions)	19,146.28
Short Ratio	1.53
Last Split Date	N/A

Dividend Information

Dividend Yield	4.63%
Annual Dividend	$1.84
Payout Ratio	0.59
Change in Payout Ratio	0.04
Last Dividend Payout / Amount	08/08/2011 / $0.46

EPS Information

Current Quarter EPS Consensus Estimate	0.41
Current Year EPS Consensus Estimate	3.12
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	01/27/2012

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	2.31
30 Days Ago	2.31
60 Days Ago	2.19
90 Days Ago	2.24

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.73	vs. Previous Year	1.74%	vs. Previous Year	4.88%
Trailing 12 Months:	12.81	vs. Previous Quarter	60.27%	vs. Previous Quarter:	19.44%
PEG Ratio	3.18				

Price Ratios		ROE		ROA	
Price/Book	1.31	09/30/11	10.64	09/30/11	2.93

Price/Cash Flow	5.94	06/30/11	10.73	06/30/11	2.93
Price / Sales	1.28	03/31/11	10.88	03/31/11	2.94
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.77	09/30/11	0.56	09/30/11	9.93
06/30/11	0.81	06/30/11	0.59	06/30/11	9.97
03/31/11	0.80	03/31/11	0.58	03/31/11	10.15
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	16.13	09/30/11	16.13	09/30/11	30.38
06/30/11	15.18	06/30/11	15.18	06/30/11	28.93
03/31/11	13.23	03/31/11	13.23	03/31/11	28.64
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.31	09/30/11	1.04	09/30/11	50.89
06/30/11	6.78	06/30/11	1.12	06/30/11	52.85
03/31/11	6.52	03/31/11	1.13	03/31/11	53.24

Zacks.com Quotes and Research

CENTERPOINT ENERGY INC (NYSE)					**ZACKS RANK: 3 - HOLD**
CNP	20.36	▲0.05	(0.25%)	Vol. 1,945,008	15:12 ET

CenterPoint Energy is a domestic energy delivery company that includes electricity transmission and distribution, natural gas distribution and sales, interstate pipeline and gathering operations. They serve customers in Arkansas, Illinois, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

General Information

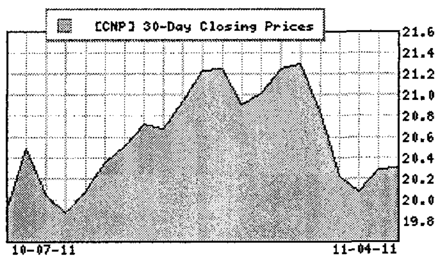
CENTERPOINT EGY
1111 LOUISIANA ST.
HOUSTON, TX 77002
Phone: 7132073000
Fax: 713-207-3169
Web: http://www.centerpointenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	03/06/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.31
52 Week High	21.47
52 Week Low	15.09
Beta	0.65
20 Day Moving Average	5,139,217.00
Target Price Consensus	21.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.91	4 Week	-6.04
12 Week	8.61	12 Week	2.16
YTD	29.20	YTD	29.65

Share Information		Dividend Information	
Shares Outstanding (millions)	425.86	Dividend Yield	3.89%
		Annual Dividend	$0.79
Market Capitalization (millions)	8,649.14	Payout Ratio	0.64
Short Ratio	1.28	Change in Payout Ratio	-0.02
Last Split Date	12/11/1995	Last Dividend Payout / Amount	08/12/2011 / $0.20

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.20	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.13	30 Days Ago	1.85
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	1.85
Next EPS Report Date	03/06/2012	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.02	vs. Previous Year	27.59%	vs. Previous Year	-1.42%
Trailing 12 Months:	16.38	vs. Previous Quarter	54.17%	vs. Previous Quarter:	2.40%
PEG Ratio	3.18				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.06	09/30/11	15.10	09/30/11	2.64

Price/Cash Flow	6.39	06/30/11	15.31	06/30/11	2.52
Price / Sales	1.03	03/31/11	14.82	03/31/11	2.40
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.85	09/30/11	0.67	09/30/11	6.28
06/30/11	0.86	06/30/11	0.73	06/30/11	5.86
03/31/11	0.92	03/31/11	0.83	03/31/11	5.62
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	14.03	09/30/11	14.03	09/30/11	9.88
06/30/11	9.35	06/30/11	9.35	06/30/11	7.79
03/31/11	8.67	03/31/11	8.67	03/31/11	7.68
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	17.98	09/30/11	2.02	09/30/11	66.88
06/30/11	18.39	06/30/11	2.57	06/30/11	71.98
03/31/11	18.37	03/31/11	2.67	03/31/11	72.78

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CLECO CORP NEW (NYSE) ZACKS RANK: 1 - STRONG BUY

CNL 36.80 ▲0.14 (0.38%) Vol. 392,184 15:12 ET

Cleco Corp. is an energy services company based in central Louisiana. Their two primary businesses are Cleco Power LLC, a regulated electric utility business, and Cleco Midstream Resources LLC, a wholesale energy business. They use a mixture of western coal, petroleum coke (petcoke), lignite, oil, and natural gas to serve their customers. This diverse fuel mix helps Cleco deliver reliable, low-cost power to its customers.

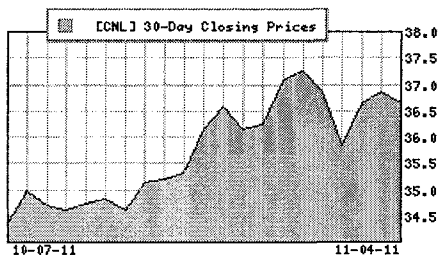
General Information

CLECO CORP
2030 DONAHUE FERRY ROAD
PINEVILLE, LA 71361-5000
Phone: 3184847400
Fax: 318-484-7465
Web: http://www.cleco.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.66
52 Week High	37.74
52 Week Low	30.05
Beta	0.50
20 Day Moving Average	568,663.88
Target Price Consensus	37.83



% Price Change		% Price Change Relative to S&P 500	
4 Week	6.69	4 Week	-1.63
12 Week	9.76	12 Week	3.24
YTD	19.18	YTD	19.60

Share Information		Dividend Information	
Shares Outstanding (millions)	61.06	Dividend Yield	3.41%
		Annual Dividend	$1.25
Market Capitalization (millions)	2,238.53	Payout Ratio	0.46
Short Ratio	4.37	Change in Payout Ratio	-0.10
Last Split Date	05/22/2001	Last Dividend Payout / Amount	11/03/2011 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	2.37	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	2.25
Next EPS Report Date	02/23/2012	90 Days Ago	2.40

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.45	vs. Previous Year	31.33%	vs. Previous Year	2.24%
Trailing 12 Months:	15.15	vs. Previous Quarter	109.62%	vs. Previous Quarter:	28.82%
PEG Ratio	2.21				

Price Ratios		ROE		ROA	
Price/Book	1.59	09/30/11	10.86	09/30/11	3.62

Price/Cash Flow	7.24	06/30/11	9.84	06/30/11	3.24
Price / Sales	1.97	03/31/11	10.19	03/31/11	3.31
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.51	09/30/11	1.25	09/30/11	12.99
06/30/11	1.49	06/30/11	1.24	06/30/11	11.64
03/31/11	1.00	03/31/11	0.78	03/31/11	11.77
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	24.11	09/30/11	24.11	09/30/11	23.03
06/30/11	23.32	06/30/11	23.32	06/30/11	22.75
03/31/11	18.46	03/31/11	18.46	03/31/11	21.86
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	5.11	09/30/11	0.97	09/30/11	49.36
06/30/11	4.74	06/30/11	1.00	06/30/11	50.01
03/31/11	4.44	03/31/11	1.03	03/31/11	50.81

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CMS ENERGY CORP (NYSE)						**ZACKS RANK: 3 - HOLD**
CMS	20.71	▲ 0.12	(0.58%)	Vol. 1,346,071	15:14 ET	

CMS Energy Corporation is a diversified energy company operating in the United States and around the world. The company's two principal subsidiaries are Consumers Energy Company and CMS Enterprises Company. Consumers Energy Company is a public utility that provides natural gas or electricity to residents in Michigan's lower peninsula. CMS Enterprises Company, through subsidiaries, is engaged in several domestic and international diversified energy businesses.

General Information

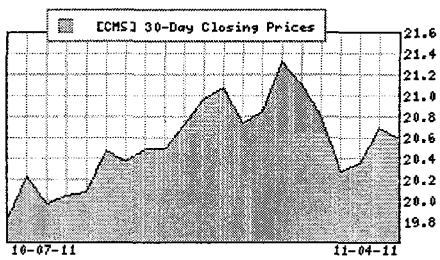
CMS ENERGY
ONE ENERGY PLAZA
JACKSON, MI 49201
Phone: 5177881612
Fax: 517-788-1859
Web: http://www.cmsenergy.com
Email: invstrel@cmsenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	20.59
52 Week High	21.58
52 Week Low	16.96
Beta	0.53
20 Day Moving Average	3,475,116.50
Target Price Consensus	22.73



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.88	4 Week	-4.22
12 Week	12.88	12 Week	6.18
YTD	10.70	YTD	11.09

Share Information		Dividend Information	
Shares Outstanding (millions)	253.36	Dividend Yield	4.08%
		Annual Dividend	$0.84
Market Capitalization (millions)	5,216.60	Payout Ratio	0.56
Short Ratio	3.25	Change in Payout Ratio	0.19
Last Split Date	N/A	Last Dividend Payout / Amount	11/02/2011 / $0.21

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.37	Current (1=Strong Buy, 5=Strong Sell)	1.92
Current Year EPS Consensus Estimate	1.45	30 Days Ago	1.77
Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	1.77
Next EPS Report Date	02/23/2012	90 Days Ago	1.77

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.23	vs. Previous Year	1.92%	vs. Previous Year	1.46%
Trailing 12 Months:	13.64	vs. Previous Quarter	103.85%	vs. Previous Quarter:	7.33%
PEG Ratio	2.59				
Price Ratios		**ROE**		**ROA**	

Price/Book	1.69	09/30/11	13.32	09/30/11	2.50
Price/Cash Flow	5.15	06/30/11	13.72	06/30/11	2.54
Price / Sales	0.79	03/31/11	13.91	03/31/11	2.56
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.29	09/30/11	0.71	09/30/11	6.02
06/30/11	1.32	06/30/11	0.89	06/30/11	6.10
03/31/11	1.20	03/31/11	0.89	03/31/11	6.07
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	8.99	09/30/11	8.99	09/30/11	12.18
06/30/11	9.20	06/30/11	9.20	06/30/11	11.89
03/31/11	9.97	03/31/11	9.97	03/31/11	11.62
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	4.67	09/30/11	2.01	09/30/11	66.79
06/30/11	4.50	06/30/11	2.12	06/30/11	67.94
03/31/11	4.36	03/31/11	2.08	03/31/11	67.57

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CONSTELLATION ENERGY GROUP I (NYSE)

ZACKS RANK: 3 - HOLD

CEG 39.99 +0.78 (1.99%) Vol. 1,318,856 15:14 ET

Baltimore Gas and Electric Company consists primarily of generating, purchasing, and selling electricity and purchasing, transporting, and selling natural gas.

General Information

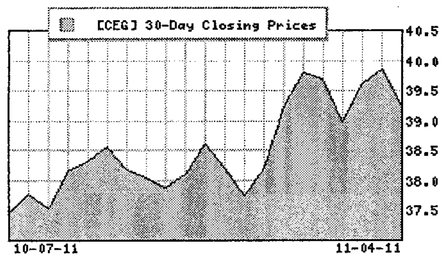
CONSTELLATN EGY
100 CONSTELLATION WAY
BALTIMORE, MD 21202
Phone: 4104702800
Fax: 410-234-5220
Web: http://www.constellation.com
Email: InvestorRelations@constellation.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	39.21
52 Week High	40.22
52 Week Low	27.64
Beta	0.97
20 Day Moving Average	2,614,567.25
Target Price Consensus	40.6



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.70	4 Week	-3.47
12 Week	9.99	12 Week	3.45
YTD	28.01	YTD	28.46

Share Information		Dividend Information	
Shares Outstanding (millions)	201.32	Dividend Yield	2.45%
		Annual Dividend	$0.96
Market Capitalization (millions)	7,893.83	Payout Ratio	0.39
Short Ratio	1.36	Change in Payout Ratio	0.02
Last Split Date	05/18/1992	Last Dividend Payout / Amount	09/08/2011 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.64	Current (1=Strong Buy, 5=Strong Sell)	2.75
Current Year EPS Consensus Estimate	2.98	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	4.80	60 Days Ago	2.75
Next EPS Report Date	02/10/2012	90 Days Ago	2.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.14	vs. Previous Year	41.67%	vs. Previous Year	-11.28%
Trailing 12 Months:	15.75	vs. Previous Quarter	-10.53%	vs. Previous Quarter:	4.80%
PEG Ratio	2.76				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.98	09/30/11	6.44	09/30/11	2.61
Price/Cash Flow	5.27	06/30/11	6.02	06/30/11	2.44

Price / Sales	0.57	03/31/11	5.76	03/31/11	2.34
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.57	09/30/11	1.39	09/30/11	3.72
06/30/11	1.64	06/30/11	1.45	06/30/11	3.32
03/31/11	1.80	03/31/11	1.62	03/31/11	3.29
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	5.57	09/30/11	5.57	09/30/11	40.19
06/30/11	-11.79	06/30/11	-11.79	06/30/11	40.43
03/31/11	-12.25	03/31/11	-12.25	03/31/11	40.29
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	20.35	09/30/11	0.56	09/30/11	35.48
06/30/11	22.89	06/30/11	0.53	06/30/11	34.21
03/31/11	24.03	03/31/11	0.55	03/31/11	35.02

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DTE ENERGY CO (NYSE)

ZACKS RANK: 3 - HOLD

DTE 52.07 -0.05 (-0.10%) Vol. 661,000 15:15 ET

DTE Energy is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its largest operating units are Detroit Edison, an electric utility serving 2.1 million customers in Southeastern Michigan, and MichCon, a natural gas utility serving 1.2 million customers in Michigan. Detroit Edison is the Company's principal operating subsidiary. Affiliates of the Company are engaged in non-regulated businesses, including energy-related services and products.

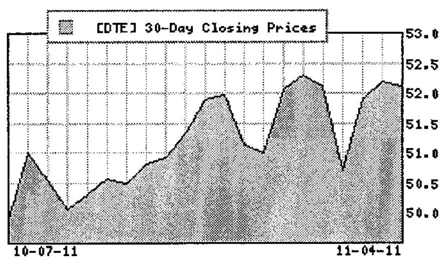
General Information

DTE ENERGY CO
ONE ENERGY PLAZA
DETROIT, MI 48226
Phone: 3132354000
Fax: -
Web: eMail: sholdersvcs@dteenergy.com
Email: www.bnymellon.com/shareowner/isd

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/08/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	52.12
52 Week High	52.82
52 Week Low	43.22
Beta	0.65
20 Day Moving Average	1,151,856.63
Target Price Consensus	51.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.43	4 Week	-3.72
12 Week	11.01	12 Week	4.42
YTD	15.00	YTD	15.41

Share Information		Dividend Information	
Shares Outstanding (millions)	169.33	Dividend Yield	4.51%
		Annual Dividend	$2.35
Market Capitalization (millions)	8,825.43	Payout Ratio	0.63
Short Ratio	1.57	Change in Payout Ratio	-0.01
Last Split Date	N/A	Last Dividend Payout / Amount	09/15/2011 / $0.59

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.87	Current (1=Strong Buy, 5=Strong Sell)	2.90
Current Year EPS Consensus Estimate	3.60	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.67
Next EPS Report Date	02/08/2012	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.46	vs. Previous Year	11.46%	vs. Previous Year	5.89%
Trailing 12 Months:	14.05	vs. Previous Quarter	64.62%	vs. Previous Quarter:	11.69%
PEG Ratio	2.89				

Price Ratios	ROE	ROA

Price/Book	1.26	09/30/11	9.20	09/30/11	2.56
Price/Cash Flow	5.39	06/30/11	9.02	06/30/11	2.49
Price / Sales	0.99	03/31/11	8.43	03/31/11	2.32
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.39	09/30/11	1.02	09/30/11	7.09
06/30/11	1.23	06/30/11	0.93	06/30/11	6.97
03/31/11	1.10	03/31/11	0.89	03/31/11	6.64
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	10.77	09/30/11	10.77	09/30/11	41.39
06/30/11	10.60	06/30/11	10.60	06/30/11	40.30
03/31/11	10.37	03/31/11	10.37	03/31/11	40.37
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.27	09/30/11	1.07	09/30/11	51.68
06/30/11	9.23	06/30/11	1.10	06/30/11	52.38
03/31/11	9.34	03/31/11	1.03	03/31/11	50.64

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EDISON INTL (NYSE) **ZACKS RANK: 3 - HOLD**

EIX 41.03 0.27 (0.66%) Vol. 1,282,702 15:16 ET

Edison International is an international electric power generator, distributor and structured finance provider. Edison International is one of the industry leaders in privatized, deregulated and incentive-regulated markets and power generation. It is the parent company of Edison Mission Energy, Southern California Edison, Edison Capita, Edison Enterprises and Edison O&M Services. (Company Press Release)

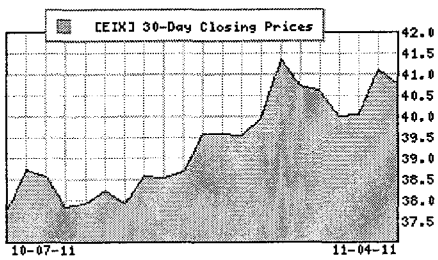
General Information
EDISON INTL
2244 WALNUT GROVE AVE STE 369 P O BOX 800
ROSEMEAD, CA 91770
Phone: (626) 302-2222
Fax: 626-302-2117
Web: http://www.edison.com
Email: invrel@sce.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	03/05/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.76
52 Week High	41.57
52 Week Low	32.64
Beta	0.66
20 Day Moving Average	2,342,882.75
Target Price Consensus	42.25



% Price Change

4 Week	8.00
12 Week	17.19
YTD	5.60

% Price Change Relative to S&P 500

4 Week	-0.42
12 Week	10.23
YTD	5.97

Share Information

Shares Outstanding (millions)	325.81
Market Capitalization (millions)	13,280.06
Short Ratio	1.47
Last Split Date	06/22/1993

Dividend Information

Dividend Yield	3.14%
Annual Dividend	$1.28
Payout Ratio	0.42
Change in Payout Ratio	0.06
Last Dividend Payout / Amount	09/28/2011 / $0.32

EPS Information

Current Quarter EPS Consensus Estimate	0.45
Current Year EPS Consensus Estimate	2.93
Estimated Long-Term EPS Growth Rate	5.00
Next EPS Report Date	03/05/2012

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.71
30 Days Ago	1.71
60 Days Ago	1.86
90 Days Ago	2.13

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.90	vs. Previous Year	-10.27%	vs. Previous Year	-10.61%
Trailing 12 Months:	13.36	vs. Previous Quarter	142.59%	vs. Previous Quarter:	13.51%
PEG Ratio	2.78				

Price Ratios **ROE** **ROA**

Price/Book	1.21	09/30/11	9.35	09/30/11	2.16
Price/Cash Flow	4.78	06/30/11	9.95	06/30/11	2.30
Price / Sales	1.09	03/31/11	10.19	03/31/11	2.38
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.14	09/30/11	1.00	09/30/11	8.22
06/30/11	1.12	06/30/11	0.97	06/30/11	8.41
03/31/11	1.17	03/31/11	1.02	03/31/11	8.66
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	12.18	09/30/11	12.18	09/30/11	33.81
06/30/11	12.51	06/30/11	12.51	06/30/11	32.93
03/31/11	12.48	03/31/11	12.48	03/31/11	32.78
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	15.48	09/30/11	1.18	09/30/11	51.92
06/30/11	15.45	06/30/11	1.21	06/30/11	52.43
03/31/11	15.40	03/31/11	1.17	03/31/11	51.68

ZACKS INVESTMENT RESEARCH
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Zacks.com Quotes and Research

GREAT PLAINS ENERGY INC (NYSE)	ZACKS RANK: 3 - HOLD
GXP 21.24 ▲0.10 (0.47%) Vol. 881,157 15:17 ET	

Great Plains Energy Incorporated engages in the generation, transmission, distribution and sale of electricity to customers located in all or portions of numerous counties in western Missouri and eastern Kansas. Customers include residences, commercial firms, and industrials, municipalities and other electric utilities.

General Information

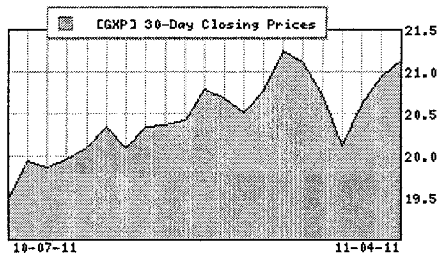
GREAT PLAINS EN
1200 MAIN ST.
KANSAS CITY, MO 64106-2124
Phone: 8165562200
Fax: 816-556-2446
Web: http://www.greatplainsenergy.com
Email: eula.jones@kcpl.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	21.14
52 Week High	21.33
52 Week Low	16.34
Beta	0.71
20 Day Moving Average	1,138,111.63
Target Price Consensus	21



% Price Change		% Price Change Relative to S&P 500	
4 Week	8.52	4 Week	0.06
12 Week	18.03	12 Week	11.02
YTD	9.03	YTD	9.41

Share Information		Dividend Information	
Shares Outstanding (millions)	135.95	Dividend Yield	3.93%
		Annual Dividend	$0.83
Market Capitalization (millions)	2,873.94	Payout Ratio	0.70
Short Ratio	4.44	Change in Payout Ratio	-0.10
Last Split Date	06/01/1992	Last Dividend Payout / Amount	08/25/2011 / $0.21

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.02	Current (1=Strong Buy, 5=Strong Sell)	2.25
Current Year EPS Consensus Estimate	1.26	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	1.86
Next EPS Report Date	02/23/2012	90 Days Ago	1.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.78	vs. Previous Year	-5.21%	vs. Previous Year	6.16%
Trailing 12 Months:	17.76	vs. Previous Quarter	193.55%	vs. Previous Quarter:	36.91%
PEG Ratio	2.58				
Price Ratios		**ROE**		**ROA**	
Price/Book	0.96	09/30/11	5.76	09/30/11	1.88

Price/Cash Flow	5.09	06/30/11	5.99	06/30/11	1.96
Price / Sales	1.25	03/31/11	6.75	03/31/11	2.21
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.44	09/30/11	0.30	09/30/11	7.28
06/30/11	0.42	06/30/11	0.28	06/30/11	7.67
03/31/11	0.39	03/31/11	0.23	03/31/11	8.65
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	10.66	09/30/11	10.66	09/30/11	21.95
06/30/11	10.89	06/30/11	10.89	06/30/11	21.19
03/31/11	12.47	03/31/11	12.47	03/31/11	21.12
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	3.19	09/30/11	0.92	09/30/11	47.64
06/30/11	3.10	06/30/11	0.99	06/30/11	49.49
03/31/11	2.91	03/31/11	0.98	03/31/11	49.15

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HAWAIIAN ELEC INDUSTRIES (NYSE)

ZACKS RANK: 4 - SELL

HE 25.84 ▼-0.84 (-3.15%) Vol. 614,907 15:17 ET

Hawaiian Electric Industries, Inc. is a holding company with subsidiaries engaged in the electric utility, savings bank, freight transportation, real estate development and other businesses, primarily in the State of Hawaii, and in the pursuit of independent power projects in Asia and the Pacific.

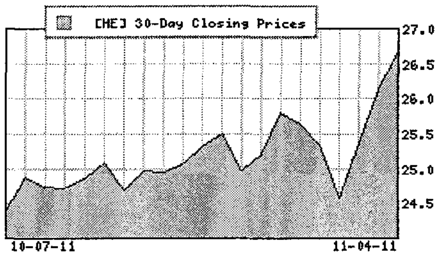
General Information

HAWAIIAN ELEC
900 RICHARDS ST
HONOLULU, HI 96813
Phone: 8085435662
Fax: 808-543-7966
Web: http://www.hei.com
Email: skimura@hei.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/09/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.68
52 Week High	26.79
52 Week Low	20.59
Beta	0.51
20 Day Moving Average	465,346.41
Target Price Consensus	24.9



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.34	4 Week	0.81
12 Week	18.95	12 Week	11.88
YTD	17.07	YTD	17.48

Share Information		Dividend Information	
Shares Outstanding (millions)	95.88	Dividend Yield	4.65%
		Annual Dividend	$1.24
Market Capitalization (millions)	2,558.02	Payout Ratio	0.93
Short Ratio	5.75	Change in Payout Ratio	-0.09
Last Split Date	06/14/2004	Last Dividend Payout / Amount	08/11/2011 / $0.31

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.38	Current (1=Strong Buy, 5=Strong Sell)	2.80
Current Year EPS Consensus Estimate	1.40	30 Days Ago	2.80
Estimated Long-Term EPS Growth Rate	8.60	60 Days Ago	2.80
Next EPS Report Date	02/09/2012	90 Days Ago	2.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.03	vs. Previous Year	42.86%	vs. Previous Year	27.62%
Trailing 12 Months:	19.91	vs. Previous Quarter	78.57%	vs. Previous Quarter:	11.59%
PEG Ratio	2.22				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.66	09/30/11	8.66	09/30/11	1.42

Price/Cash Flow	9.15	06/30/11	7.68	06/30/11	1.26
Price / Sales	0.83	03/31/11	7.88	03/31/11	1.30
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.94	09/30/11	0.94	09/30/11	4.23
06/30/11	0.93	06/30/11	0.93	06/30/11	3.96
03/31/11	0.93	03/31/11	0.93	03/31/11	4.24
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	6.62	09/30/11	6.62	09/30/11	16.04
06/30/11	6.25	06/30/11	6.25	06/30/11	15.87
03/31/11	6.72	03/31/11	6.72	03/31/11	15.77
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	-	09/30/11	0.87	09/30/11	47.19
06/30/11	-	06/30/11	0.95	06/30/11	49.37
03/31/11	-	03/31/11	0.96	03/31/11	49.63

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IDACORP INC (NYSE)

ZACKS RANK: 2 - BUY

IDA	40.43	N/A	(N/A%)	Vol. 106,455	15:18 ET

Idacorp Inc. is an electric public utility company. The company is engaged in the generation, purchase, transmission, distribution and sale of electric energy primarily in the areas including southern Idaho, eastern Oregon and northern Nevada. The company relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydro base. The company's principal commercial and industrial customers include lodges, condominiums, and ski lifts and related facilities.

General Information

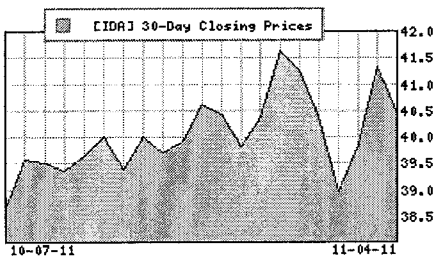
IDACORP INC
1221 WEST IDAHO STREET
BOISE, ID 83702-5627
Phone: 2083882200
Fax: 208-388-6916
Web: www.idacorpinc.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/22/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	40.43
52 Week High	41.97
52 Week Low	33.88
Beta	0.44
20 Day Moving Average	300,403.66
Target Price Consensus	41



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.61	4 Week	-3.56
12 Week	11.81	12 Week	5.17
YTD	9.33	YTD	9.71

Share Information		Dividend Information	
Shares Outstanding (millions)	49.71	Dividend Yield	2.97%
		Annual Dividend	$1.20
Market Capitalization (millions)	2,009.86	Payout Ratio	0.49
Short Ratio	4.27	Change in Payout Ratio	-0.03
Last Split Date	N/A	Last Dividend Payout / Amount	11/03/2011 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.46	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	3.40	30 Days Ago	2.17
Estimated Long-Term EPS Growth Rate	4.70	60 Days Ago	2.33
Next EPS Report Date	02/22/2012	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.89	vs. Previous Year	-27.34%	vs. Previous Year	0.09%
Trailing 12 Months:	16.57	vs. Previous Quarter	140.48%	vs. Previous Quarter:	31.77%
PEG Ratio	2.55				

Price Ratios	ROE	ROA

Price/Book	1.21	09/30/11	7.67	09/30/11	2.59
Price/Cash Flow	7.50	06/30/11	8.95	06/30/11	2.99
Price / Sales	1.95	03/31/11	10.35	03/31/11	3.45
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.22	09/30/11	0.84	09/30/11	11.79
06/30/11	0.96	06/30/11	0.68	06/30/11	13.44
03/31/11	1.02	03/31/11	0.78	03/31/11	15.13
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	13.47	09/30/11	13.47	09/30/11	33.41
06/30/11	14.95	06/30/11	14.95	06/30/11	31.61
03/31/11	15.36	03/31/11	15.36	03/31/11	31.43
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	7.46	09/30/11	0.90	09/30/11	47.25
06/30/11	7.74	06/30/11	0.95	06/30/11	48.70
03/31/11	8.23	03/31/11	0.96	03/31/11	48.91

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INTEGRYS ENERGY GROUP INC (NYSE)

ZACKS RANK: 2 - BUY

TEG 52.65 ▾-0.29 (-0.55%) Vol. 549,680 15:18 ET

Integrys Energy Group is a diversified holding company with regulated utility operations operating through six wholly owned subsidiaries. These include the Wisconsin Public Service Corporation, The Peoples Gas Light and Coke Company, North Shore Gas Company, Upper Peninsula Power Company, Michigan Gas Utilities Corporation, and Minnesota Energy Resources Corporation; nonregulated operations serving the competitive energy markets through its wholly owned nonregulated subsidiary, Integrys Energy Services; and also a 34% equity ownership interest in American Transmission Company LLC (an electric transmission company operating in Wisconsin, Michigan, Minnesota, and Illinois).

General Information

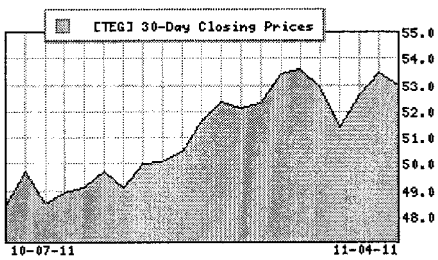
INTEGRYS ENERGY
130 EAST RANDOLPH DRIVE
CHICAGO, IL 60601
Phone: 800-699-1269
Fax: -
Web: www.integrysgroup.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/22/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	52.94
52 Week High	54.02
52 Week Low	42.76
Beta	0.85
20 Day Moving Average	585,687.00
Target Price Consensus	51.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.34	4 Week	0.81
12 Week	12.71	12 Week	6.02
YTD	9.13	YTD	9.52

Share Information		Dividend Information	
Shares Outstanding (millions)	78.29	Dividend Yield	5.14%
		Annual Dividend	$2.72
Market Capitalization (millions)	4,144.57	Payout Ratio	0.85
Short Ratio	5.87	Change in Payout Ratio	-0.06
Last Split Date	N/A	Last Dividend Payout / Amount	08/29/2011 / $0.68

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.05	Current (1=Strong Buy, 5=Strong Sell)	2.57
Current Year EPS Consensus Estimate	3.37	30 Days Ago	2.57
Estimated Long-Term EPS Growth Rate	4.50	60 Days Ago	2.71
Next EPS Report Date	02/22/2012	90 Days Ago	2.71

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.73	vs. Previous Year	22.86%	vs. Previous Year	-5.93%
Trailing 12 Months:	16.54	vs. Previous Quarter	13.16%	vs. Previous Quarter:	-7.13%
PEG Ratio	3.50				

Price Ratios		ROE		ROA	
Price/Book	1.40	09/30/11	8.55	09/30/11	2.65
Price/Cash Flow	8.06	06/30/11	8.39	06/30/11	2.57
Price / Sales	0.85	03/31/11	8.62	03/31/11	2.63
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.32	09/30/11	1.06	09/30/11	5.21
06/30/11	1.41	06/30/11	1.28	06/30/11	5.01
03/31/11	1.36	03/31/11	1.29	03/31/11	5.11
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	8.83	09/30/11	8.83	09/30/11	37.90
06/30/11	8.11	06/30/11	8.11	06/30/11	38.09
03/31/11	9.47	03/31/11	9.47	03/31/11	38.47
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	19.87	09/30/11	0.70	09/30/11	40.81
06/30/11	19.71	06/30/11	0.71	06/30/11	41.27
03/31/11	19.57	03/31/11	0.72	03/31/11	41.46

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ITC HLDGS CORP (NYSE)

ZACKS RANK: 3 - HOLD

ITC	74.85	▼-0.33	(-0.44%)	Vol. 135,111	15:19 ET

ITC Holdings Corp. is in the business of electricity transmission infrastructure improvements as a means to improve electric reliability, reduce congestion and lower the overall cost of delivered energy. Through ITC operating subsidiaries, ITCTransmission and METC, we are the only publicly traded company engaged exclusively in the transmission of electricity in the United States. We are also the largest independent electric transmission company and the eighth largest electric transmission company in the country based on transmission load served. Its business strategy is to operate, maintain and invest in our transmission infrastructure in order to enhance system integrity and reliability and to reduce transmission constraints. By pursuing this strategy, we seek to reduce the overall cost of delivered energy for end-use consumers by providing them with access to electricity from the lowest cost electricity generation sources.

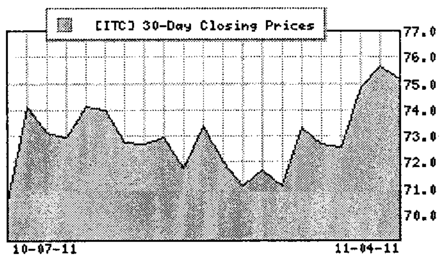
General Information

ITC HOLDINGS CP
27175 ENERGY WAY
NOVI, MI 48377
Phone: 248-946-3000
Fax: -
Web: http://www.itc-holdings.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/21/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	75.18
52 Week High	78.89
52 Week Low	59.77
Beta	0.64
20 Day Moving Average	473,241.66
Target Price Consensus	80.83



% Price Change		% Price Change Relative to S&P 500	
4 Week	6.71	4 Week	-1.61
12 Week	6.25	12 Week	-0.06
YTD	21.30	YTD	21.72

Share Information		Dividend Information	
Shares Outstanding (millions)	51.30	Dividend Yield	1.88%
		Annual Dividend	$1.41
Market Capitalization (millions)	3,856.43	Payout Ratio	0.44
Short Ratio	6.93	Change in Payout Ratio	-0.16
Last Split Date	N/A	Last Dividend Payout / Amount	08/30/2011 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.84	Current (1=Strong Buy, 5=Strong Sell)	1.75
Current Year EPS Consensus Estimate	3.33	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	16.50	60 Days Ago	1.29
Next EPS Report Date	02/21/2012	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	22.60	vs. Previous Year	13.33%	vs. Previous Year	7.46%

Trailing 12 Months:	23.49	vs. Previous Quarter	2.41%	vs. Previous Quarter:	3.35%
PEG Ratio	1.37				
Price Ratios		**ROE**		**ROA**	
Price/Book	3.20	09/30/11	14.21	09/30/11	3.71
Price/Cash Flow	16.37	06/30/11	14.08	06/30/11	3.67
Price / Sales	5.18	03/31/11	13.90	03/31/11	3.59
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.99	09/30/11	0.80	09/30/11	22.26
06/30/11	1.02	06/30/11	0.85	06/30/11	21.89
03/31/11	1.17	03/31/11	0.94	03/31/11	21.47
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	34.37	09/30/11	34.37	09/30/11	23.51
06/30/11	34.22	06/30/11	34.22	06/30/11	23.32
03/31/11	33.71	03/31/11	33.71	03/31/11	22.75
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	3.26	09/30/11	2.14	09/30/11	68.12
06/30/11	3.13	06/30/11	2.16	06/30/11	68.31
03/31/11	3.13	03/31/11	2.18	03/31/11	68.52

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PEPCO HOLDINGS INC (NYSE)	**ZACKS RANK: 3 - HOLD**
POM 19.51 ▼-0.07 (-0.36%) Vol. 868,037 15:20 ET	

Pepco Holdings, Inc. is an energy holding company. Pepco has been providing reliable electric service for more than one hundred years. Today, they deliver electricity to homes and businesses in the District of Columbia and its Maryland suburbs.

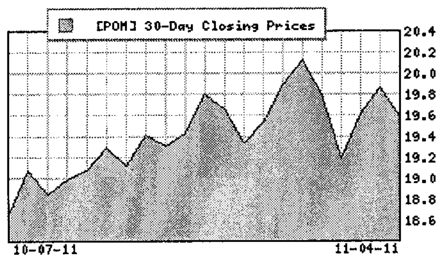
General Information

PEPCO HLDGS
SUITE 1300 701 NINTH STREET NW
WASHINGTON, DC 20068
Phone: 202-872-2000
Fax: 202-331-6750
Web: http://www.pepcoholdings.com
Email: investor@pepcoholdings.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/24/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.58
52 Week High	20.36
52 Week Low	16.57
Beta	0.52
20 Day Moving Average	1,743,203.63
Target Price Consensus	19.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.99	4 Week	-3.20
12 Week	7.88	12 Week	1.47
YTD	7.29	YTD	7.67

Share Information		Dividend Information	
Shares Outstanding (millions)	226.40	Dividend Yield	5.52%
		Annual Dividend	$1.08
Market Capitalization (millions)	4,432.83	Payout Ratio	0.84
Short Ratio	4.47	Change in Payout Ratio	0.03
Last Split Date	N/A	Last Dividend Payout / Amount	09/08/2011 / $0.27

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.16	Current (1=Strong Buy, 5=Strong Sell)	2.80
Current Year EPS Consensus Estimate	1.24	30 Days Ago	2.80
Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.78
Next EPS Report Date	02/24/2012	90 Days Ago	2.78

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.80	vs. Previous Year	-32.69%	vs. Previous Year	-20.51%
Trailing 12 Months:	15.18	vs. Previous Quarter	-16.67%	vs. Previous Quarter:	16.61%
PEG Ratio	3.95				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.02	09/30/11	6.83	09/30/11	2.04

Price/Cash Flow	6.57	06/30/11	7.73	06/30/11	2.30
Price / Sales	0.71	03/31/11	7.32	03/31/11	2.11
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.96	09/30/11	0.87	09/30/11	4.72
06/30/11	0.96	06/30/11	0.87	06/30/11	4.96
03/31/11	0.89	03/31/11	0.82	03/31/11	4.52
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	5.69	09/30/11	5.69	09/30/11	19.25
06/30/11	3.52	06/30/11	3.52	06/30/11	19.12
03/31/11	2.82	03/31/11	2.82	03/31/11	18.93
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	37.01	09/30/11	0.96	09/30/11	49.06
06/30/11	40.27	06/30/11	0.97	06/30/11	49.35
03/31/11	42.28	03/31/11	0.95	03/31/11	48.73

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PG&E CORP (NYSE)

ZACKS RANK: 3 - HOLD

PCG 40.19 ▼-0.67 (-1.64%) Vol. 2,913,573 15:21 ET

PG&E Corporation is an energy-based holding company. Pacific Gas and Electric Company, the company's primary subsidiary, is an operating public utility engaged principally in the business of providing electricity and natural gas distribution and transmission services throughout most of Northern and Central California.

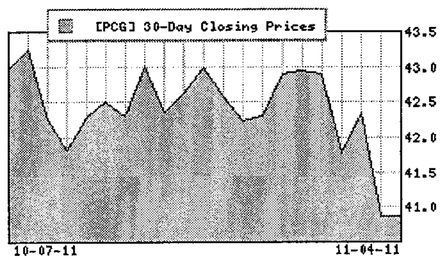
General Information

PG&E CORP
ONE MARKET SPEAR TOWER SUITE 2400
SAN FRANCISCO, CA 94105
Phone: 4152677000
Fax: 415-267-7268
Web: http://www.pgecorp.com
Email: invrel@pge-corp.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/16/2012

Price and Volume Information

Zacks Rank	2
Yesterday's Close	40.86
52 Week High	48.63
52 Week Low	37.57
Beta	0.30
20 Day Moving Average	3,231,359.50
Target Price Consensus	44.65



% Price Change		% Price Change Relative to S&P 500	
4 Week	-4.91	4 Week	-12.33
12 Week	2.51	12 Week	-3.58
YTD	-14.59	YTD	-14.29

Share Information		Dividend Information	
Shares Outstanding (millions)	402.24	Dividend Yield	4.45%
		Annual Dividend	$1.82
Market Capitalization (millions)	16,435.73	Payout Ratio	0.54
Short Ratio	1.49	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	09/29/2011 / $0.46

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.83	Current (1=Strong Buy, 5=Strong Sell)	1.87
Current Year EPS Consensus Estimate	3.52	30 Days Ago	1.87
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	1.94
Next EPS Report Date	02/16/2012	90 Days Ago	1.94

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.60	vs. Previous Year	5.88%	vs. Previous Year	9.88%
Trailing 12 Months:	12.09	vs. Previous Quarter	5.88%	vs. Previous Quarter:	4.78%
PEG Ratio	2.32				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.35	09/30/11	11.49	09/30/11	2.91

Price/Cash Flow	4.59	06/30/11	11.40	06/30/11	2.87
Price / Sales	1.11	03/31/11	11.13	03/31/11	2.79
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.86	09/30/11	0.80	09/30/11	9.23
06/30/11	0.87	06/30/11	0.82	06/30/11	9.19
03/31/11	0.70	03/31/11	0.67	03/31/11	9.09
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	9.77	09/30/11	9.77	09/30/11	30.36
06/30/11	10.81	06/30/11	10.81	06/30/11	30.26
03/31/11	11.03	03/31/11	11.03	03/31/11	29.44
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	29.68	09/30/11	1.33	09/30/11	57.05
06/30/11	29.41	06/30/11	0.97	06/30/11	49.26
03/31/11	28.91	03/31/11	0.91	03/31/11	47.64

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PORTLAND GEN ELEC CO (NYSE)

ZACKS RANK: 3 - HOLD

POR 25.03 ▾-0.11 (-0.44%) Vol. 420,406 15:22 ET

Portland General Electric, headquartered in Portland, Ore., is a vertically integrated electric utility that serves residential, commercial and industrial customers in Oregon. The company has more than a century of experience in power delivery. PGE generates power from a diverse mix of resources, including hydropower, coal and natural gas. PGE also participates in the wholesale market by purchasing and selling electricity and natural gas to utilities and energy marketers.

General Information

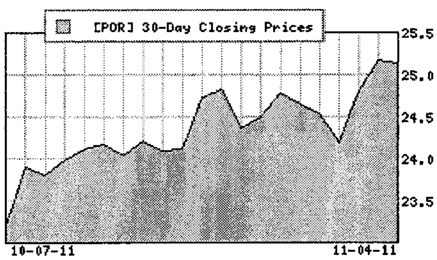
PORTLAND GEN EL
121 SW SALMON ST 1WTC0501
PORTLAND, OR 97204
Phone: 5034647779
Fax: -
Web: www.portlandgeneral.com
Email: investors@pgn.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/24/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	25.14
52 Week High	26.05
52 Week Low	20.71
Beta	0.66
20 Day Moving Average	774,833.63
Target Price Consensus	26.13



% Price Change		% Price Change Relative to S&P 500	
4 Week	8.27	4 Week	-0.18
12 Week	9.26	12 Week	2.77
YTD	15.85	YTD	16.26

Share Information		Dividend Information	
Shares Outstanding (millions)	75.34	Dividend Yield	4.22%
		Annual Dividend	$1.06
Market Capitalization (millions)	1,894.07	Payout Ratio	0.55
Short Ratio	3.08	Change in Payout Ratio	-0.02
Last Split Date	N/A	Last Dividend Payout / Amount	09/22/2011 / $0.26

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.39	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	2.01	30 Days Ago	2.44
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.44
Next EPS Report Date	02/24/2012	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.54	vs. Previous Year	-44.62%	vs. Previous Year	-5.39%
Trailing 12 Months:	13.16	vs. Previous Quarter	24.14%	vs. Previous Quarter:	6.81%
PEG Ratio	2.51				

Price Ratios	ROE	ROA

Price/Book	1.15	09/30/11	8.77	09/30/11	2.60
Price/Cash Flow	5.21	06/30/11	10.19	06/30/11	2.98
Price / Sales	1.06	03/31/11	10.46	03/31/11	3.03
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	-	09/30/11	-	09/30/11	7.99
06/30/11	1.54	06/30/11	1.39	06/30/11	9.10
03/31/11	1.54	03/31/11	1.42	03/31/11	9.19
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	-	09/30/11	-	09/30/11	-
06/30/11	12.51	06/30/11	12.51	06/30/11	21.88
03/31/11	12.54	03/31/11	12.54	03/31/11	21.84
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	-	09/30/11	-	09/30/11	-
06/30/11	16.83	06/30/11	1.09	06/30/11	52.18
03/31/11	16.90	03/31/11	1.09	03/31/11	52.22

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PPL CORP (NYSE)	**ZACKS RANK: 3 - HOLD**
PPL 29.75 +0.08 (0.27%) Vol. 1,703,780 15:22 ET	

PPL Corporation is an energy and utility holding company. PPL controls more than 12,000 megawatts of generating capacity in the United States, sells energy in key U.S. markets and delivers electricity to customers in Pennsylvania and the United Kingdom.

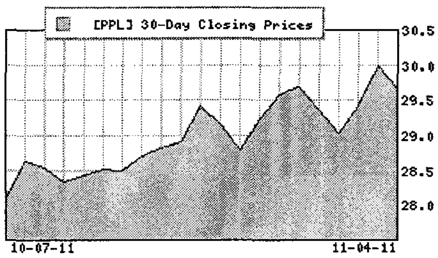
General Information

PPL CORP
TWO N NINTH ST
ALLENTOWN, PA 18101-1179
Phone: 610-774-5151
Fax: 610-774-5106
Web: http://www.pplresources.com
Email: invserv@pplweb.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.67
52 Week High	30.27
52 Week Low	24.10
Beta	0.44
20 Day Moving Average	3,650,914.75
Target Price Consensus	30.4



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.59	4 Week	-2.65
12 Week	14.11	12 Week	7.34
YTD	12.73	YTD	13.13

Share Information		Dividend Information	
Shares Outstanding (millions)	577.75	Dividend Yield	4.72%
		Annual Dividend	$1.40
Market Capitalization (millions)	17,141.81	Payout Ratio	0.48
Short Ratio	3.70	Change in Payout Ratio	-0.08
Last Split Date	08/25/2005	Last Dividend Payout / Amount	09/07/2011 / $0.35

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.62	Current (1=Strong Buy, 5=Strong Sell)	2.08
Current Year EPS Consensus Estimate	2.61	30 Days Ago	2.08
Estimated Long-Term EPS Growth Rate	12.20	60 Days Ago	2.18
Next EPS Report Date	02/10/2012	90 Days Ago	2.25

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	11.37	vs. Previous Year	2.70%	vs. Previous Year	43.18%
Trailing 12 Months:	10.27	vs. Previous Quarter	68.89%	vs. Previous Quarter:	25.35%
PEG Ratio	0.93				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.54	09/30/11	15.27	09/30/11	4.08

Price/Cash Flow	6.71	06/30/11	15.45	06/30/11	4.28
Price / Sales	1.65	03/31/11	16.50	03/31/11	4.76
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.13	09/30/11	-	09/30/11	14.46
06/30/11	1.17	06/30/11	1.03	06/30/11	15.05
03/31/11	1.17	03/31/11	1.05	03/31/11	16.63
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	18.59	09/30/11	18.59	09/30/11	19.24
06/30/11	17.96	06/30/11	17.96	06/30/11	18.92
03/31/11	17.64	03/31/11	17.64	03/31/11	18.16
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.32	09/30/11	-	09/30/11	-
06/30/11	9.67	06/30/11	1.61	06/30/11	61.62
03/31/11	9.99	03/31/11	1.39	03/31/11	58.19

Zacks.com Quotes and Research

TECO ENERGY INC (NYSE) ZACKS RANK: 3 - HOLD

TE 19.11 +0.10 (0.53%) Vol. 1,086,369 15:23 ET

TECO Energy, Inc. is a diversified, energy-related holding company. Its principal businesses are Tampa Electric, Peoples Gas, Florida's largest natural gas distributor; TECO Power Services, an independent power company; TECO Transport, a river and ocean transportation company; TECO Coal, producer of coal and synthetic fuel; and TECO Solutions, an energy services/engineering company. (Company Press Release)

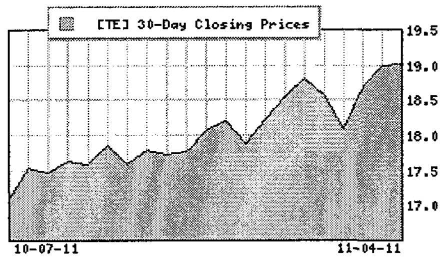
General Information

TECO ENERGY
702 N FRANKLIN ST
TAMPA, FL 33602
Phone: 8132284111
Fax: 813-228-1670
Web: http://www.tecoenergy.com
Email: investorrelations@tecoenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/10/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	19.01
52 Week High	19.66
52 Week Low	15.82
Beta	0.82
20 Day Moving Average	2,160,514.75
Target Price Consensus	18.82



% Price Change		% Price Change Relative to S&P 500	
4 Week	11.23	4 Week	2.56
12 Week	12.42	12 Week	5.74
YTD	6.80	YTD	7.17

Share Information		Dividend Information	
Shares Outstanding (millions)	215.72	Dividend Yield	4.52%
		Annual Dividend	$0.86
Market Capitalization (millions)	4,100.90	Payout Ratio	0.69
Short Ratio	2.61	Change in Payout Ratio	-0.06
Last Split Date	08/31/1993	Last Dividend Payout / Amount	08/11/2011 / $0.22

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.29	Current (1=Strong Buy, 5=Strong Sell)	2.69
Current Year EPS Consensus Estimate	1.31	30 Days Ago	2.81
Estimated Long-Term EPS Growth Rate	4.70	60 Days Ago	2.81
Next EPS Report Date	02/10/2012	90 Days Ago	2.81

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.50	vs. Previous Year	23.53%	vs. Previous Year	1.06%
Trailing 12 Months:	15.21	vs. Previous Quarter	16.67%	vs. Previous Quarter:	2.90%
PEG Ratio	3.11				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.81	09/30/11	12.15	09/30/11	3.74

Price/Cash Flow	6.94	06/30/11	11.56	06/30/11	3.50
Price / Sales	1.22	03/31/11	11.77	03/31/11	3.49
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.83	09/30/11	0.63	09/30/11	7.97
06/30/11	0.90	06/30/11	0.61	06/30/11	7.51
03/31/11	0.98	03/31/11	0.64	03/31/11	7.54
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	12.89	09/30/11	12.89	09/30/11	10.49
06/30/11	12.19	06/30/11	12.19	06/30/11	10.31
03/31/11	11.85	03/31/11	11.85	03/31/11	10.17
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.45	09/30/11	1.19	09/30/11	54.32
06/30/11	9.29	06/30/11	1.33	06/30/11	57.09
03/31/11	9.27	03/31/11	1.41	03/31/11	58.42

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Zacks.com Quotes and Research

WESTAR ENERGY INC (NYSE)

ZACKS RANK: 3 - HOLD

WR 27.29 ▲0.02 (0.07%) Vol. 1,371,210 15:24 ET

Westar Energy is a consumer services company with interests in monitored services and energy. Westar Energy provides electric utility services to customers in Kansas. Westar Energy's goal is to operate the best utility in the Midwest. They will provide their customers quality service at below average prices. Westar Energy Generation and Marketing will be a preferred energy provider, both inside and outside their service territory.

General Information

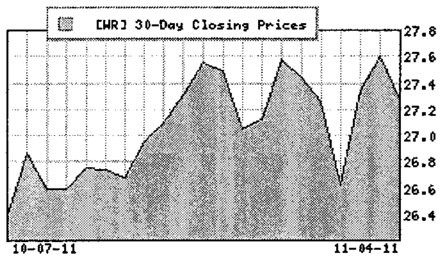
WESTAR ENERGY
818 KANSAS AVE
TOPEKA, KS 66601
Phone: 7855756300
Fax: 785-575-6596
Web: http://www.westarenergy.com
Email: ir@westarenergy.com

Industry	UTIL-ELEC PWR
Sector:	Utilities

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/23/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	27.27
52 Week High	27.98
52 Week Low	22.63
Beta	0.59
20 Day Moving Average	1,164,479.38
Target Price Consensus	28.58



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.30	4 Week	-4.76
12 Week	11.03	12 Week	4.44
YTD	8.39	YTD	8.77

Share Information		Dividend Information	
Shares Outstanding (millions)	115.81	Dividend Yield	4.69%
		Annual Dividend	$1.28
Market Capitalization (millions)	3,158.22	Payout Ratio	0.99
Short Ratio	7.76	Change in Payout Ratio	0.22
Last Split Date	N/A	Last Dividend Payout / Amount	09/07/2011 / $0.32

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.11	Current (1=Strong Buy, 5=Strong Sell)	2.00
Current Year EPS Consensus Estimate	1.77	30 Days Ago	2.00
Estimated Long-Term EPS Growth Rate	6.10	60 Days Ago	2.00
Next EPS Report Date	02/23/2012	90 Days Ago	2.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.41	vs. Previous Year	-3.92%	vs. Previous Year	5.23%
Trailing 12 Months:	21.14	vs. Previous Quarter	-%	vs. Previous Quarter:	29.20%
PEG Ratio	2.53				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.22	09/30/11	7.92	09/30/11	2.37

Price/Cash Flow	6.25	06/30/11	8.10	06/30/11	2.41
Price / Sales	1.47	03/31/11	8.63	03/31/11	2.57
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.68	09/30/11	0.45	09/30/11	9.12
06/30/11	0.68	06/30/11	0.45	06/30/11	9.28
03/31/11	0.67	03/31/11	0.41	03/31/11	9.86
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	14.69	09/30/11	14.69	09/30/11	22.42
06/30/11	13.48	06/30/11	13.48	06/30/11	21.72
03/31/11	14.18	03/31/11	14.18	03/31/11	21.26
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	5.46	09/30/11	1.06	09/30/11	51.16
06/30/11	5.40	06/30/11	1.12	06/30/11	52.57
03/31/11	5.38	03/31/11	1.14	03/31/11	53.15

ZACKS INVESTMENT RESEARCH

Proven Ratings, Research & Recommendations

Zacks.com Quotes and Research

WISCONSIN ENERGY CORP (NYSE)

ZACKS RANK: 2 - BUY

WEC 32.82 ▲0.10 (0.31%) Vol. 748,059 15:24 ET

Wisconsin Energy Corp. is a holding company with subsidiaries in utility and non-utility businesses. The company serves electric and natural gas customers in Wisconsin and Michigan's Upper Peninsula through its primary utility subsidiaries Wisconsin Electric, Wisconsin Gas and Edison Sault Electric. Its non-utility subsidiaries include energy services and development, pump manufacturing, waste-to-energy, and real estate businesses. (Company Press Release)

General Information

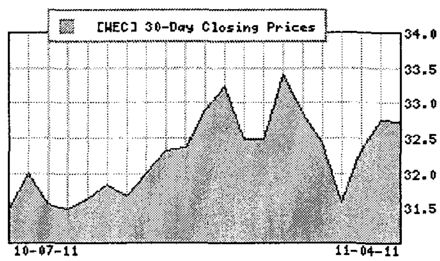
WISC ENERGY CP
231 W MICHIGAN ST .P O BOX 1331
MILWAUKEE, WI 53201
Phone: 414-221-2345
Fax: -
Web: http://www.wisconsinenergy.com
Email: None

Industry	UTIL-ELEC PWR
Sector:	*Utilities*

Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/07/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.72
52 Week High	33.63
52 Week Low	27.00
Beta	0.33
20 Day Moving Average	1,658,206.38
Target Price Consensus	34.44



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.91	4 Week	-4.20
12 Week	10.09	12 Week	3.56
YTD	11.18	YTD	11.57

Share Information		Dividend Information	
Shares Outstanding (millions)	233.74	Dividend Yield	3.18%
		Annual Dividend	$1.04
Market Capitalization (millions)	7,647.97	Payout Ratio	0.47
Short Ratio	3.46	Change in Payout Ratio	0.05
Last Split Date	03/02/2011	Last Dividend Payout / Amount	08/10/2011 / $0.26

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.50	Current (1=Strong Buy, 5=Strong Sell)	2.14
Current Year EPS Consensus Estimate	2.15	30 Days Ago	2.14
Estimated Long-Term EPS Growth Rate	7.50	60 Days Ago	2.14
Next EPS Report Date	02/07/2012	90 Days Ago	2.33

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.22	vs. Previous Year	15.79%	vs. Previous Year	8.18%
Trailing 12 Months:	14.81	vs. Previous Quarter	34.15%	vs. Previous Quarter:	6.16%
PEG Ratio	2.03				

Price Ratios	ROE	ROA

Price/Book	1.94	09/30/11	13.45	09/30/11	3.99
Price/Cash Flow	13.34	06/30/11	13.18	06/30/11	3.90
Price / Sales	1.71	03/31/11	13.14	03/31/11	3.84
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	1.04	09/30/11	0.70	09/30/11	11.75
06/30/11	1.02	06/30/11	0.73	06/30/11	11.56
03/31/11	1.09	03/31/11	0.88	03/31/11	11.59
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	17.92	09/30/11	17.92	09/30/11	16.86
06/30/11	17.69	06/30/11	17.69	06/30/11	16.89
03/31/11	17.84	03/31/11	17.84	03/31/11	16.70
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.24	09/30/11	1.17	09/30/11	53.77
06/30/11	8.90	06/30/11	1.10	06/30/11	52.15
03/31/11	8.49	03/31/11	1.11	03/31/11	52.44

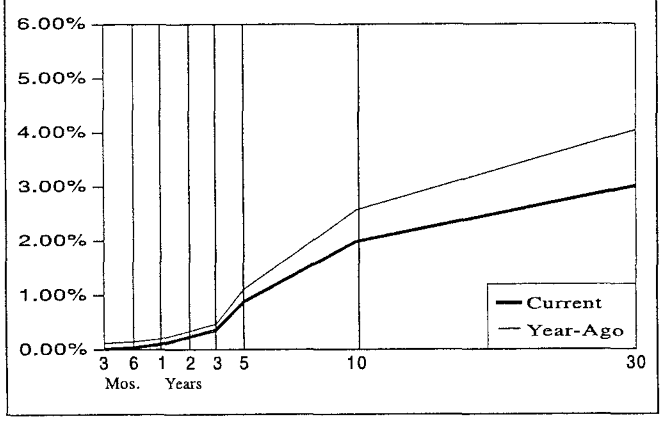
ATTACHMENT C

Selected Yields

TAXABLE	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.51	0.28	0.23
3-month LIBOR	0.43	0.27	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.53
5-year	1.14	1.62	1.57
U.S. Treasury Securities			
3-month	0.01	0.01	0.12
6-month	0.04	0.08	0.15
1-year	0.10	0.14	0.20
5-year	0.88	1.26	1.11
10-year	1.99	2.62	2.57
10-year (inflation-protected)	-0.10	0.28	0.42
30-year	3.01	3.90	4.04
30-year Zero	3.22	4.27	4.43

	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.62	1.82	1.23
FHLMC 5.5% (Gold)	2.34	2.43	1.51
FNMA 5.5%	2.10	2.36	1.27
FNMA ARM	2.43	2.49	2.81
Corporate Bonds			
Financial (10-year) A	4.15	4.09	3.99
Industrial (25/30-year) A	4.18	4.93	5.28
Utility (25/30-year) A	4.12	4.87	5.35
Utility (25/30-year) Baa/BBB	4.76	5.43	5.79
Foreign Bonds (10-Year)			
Canada	2.17	2.67	2.87
Germany	1.83	2.40	2.42
Japan	1.00	1.02	0.95
United Kingdom	2.29	2.74	3.15
Preferred Stocks			
Utility A	5.82	6.05	5.77
Financial A	6.57	6.33	6.48
Financial Adjustable A	5.50	5.50	5.50

Treasury Security Yield Curve



TAX-EXEMPT	Recent (11/02/11)	3 Months Ago (8/03/11)	Year Ago (11/03/10)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.12	4.47	3.96
25-Bond Index (Revs)	5.10	5.62	4.67
General Obligation Bonds (GOs)			
1-year Aaa	0.24	0.21	0.32
1-year A	1.05	0.96	1.13
5-year Aaa	1.28	1.20	1.31
5-year A	2.35	2.18	2.26
10-year Aaa	2.57	2.87	2.71
10-year A	3.56	4.18	3.86
25/30-year Aaa	4.03	4.28	4.23
25/30-year A	5.37	5.77	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.55	4.83	4.63
Electric AA	4.90	5.16	4.65
Housing AA	5.59	5.80	5.50
Hospital AA	4.94	5.08	4.84
Toll Road Aaa	4.55	4.90	4.64

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/19/11	**10/5/11**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1571895	1541640	30255	1573995	1556283	1339026
Borrowed Reserves	11317	11429	-112	11732	13270	23713
Net Free/Borrowed Reserves	1560578	1530211	30367	1562263	1543014	1315313

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

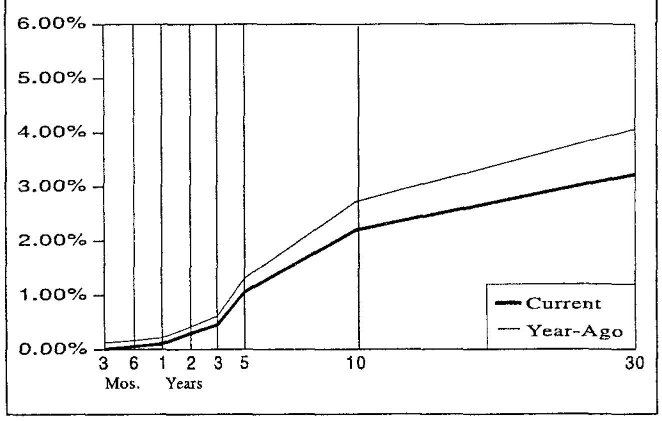
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/17/11	**10/10/11**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2150.9	2157.9	-7.0	40.8%	30.1%	21.0%
M2 (M1+savings+small time deposits)	9628.7	9622.4	6.3	16.0%	15.7%	10.2%

Selected Yields

	Recent (10/26/11)	3 Months Ago (7/27/11)	Year Ago (10/27/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.49	0.22	0.23
3-month LIBOR	0.42	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.54
5-year	1.14	1.62	1.61
U.S. Treasury Securities			
3-month	0.01	0.08	0.13
6-month	0.06	0.12	0.17
1-year	0.11	0.20	0.22
5-year	1.06	1.52	1.31
10-year	2.20	2.98	2.72
10-year (inflation-protected)	0.12	0.46	0.56
30-year	3.22	4.29	4.06
30-year Zero	3.43	4.69	4.40

	Recent (10/26/11)	3 Months Ago (7/27/11)	Year Ago (10/27/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.76	2.04	1.22
FHLMC 5.5% (Gold)	2.39	2.68	1.69
FNMA 5.5%	2.19	2.58	1.53
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.41	4.42	4.22
Industrial (25/30-year) A	4.49	5.30	5.28
Utility (25/30-year) A	4.41	5.28	5.31
Utility (25/30-year) Baa/BBB	5.05	5.82	5.86
Foreign Bonds (10-Year)			
Canada	2.38	2.88	2.89
Germany	2.04	2.65	2.57
Japan	1.00	1.09	0.96
United Kingdom	2.47	2.98	3.15
Preferred Stocks			
Utility A	5.21	5.14	5.79
Financial A	6.49	6.07	6.05
Financial Adjustable A	5.50	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.08	4.46	3.84
25-Bond Index (Revs)	5.07	5.32	4.60
General Obligation Bonds (GOs)			
1-year Aaa	0.29	0.21	0.34
1-year A	1.00	1.01	1.13
5-year Aaa	1.41	1.27	1.28
5-year A	2.42	2.27	2.24
10-year Aaa	2.69	2.92	2.64
10-year A	3.60	4.23	3.77
25/30-year Aaa	4.10	4.34	4.21
25/30-year A	5.42	5.83	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.63
Electric AA	4.94	5.19	4.65
Housing AA	5.66	5.84	5.52
Hospital AA	4.97	5.12	4.80
Toll Road Aaa	4.57	4.92	4.62

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/19/11	10/5/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1572296	1541887	30409	1574153	1556363	1339067
Borrowed Reserves	11317	11429	-112	11732	13270	23713
Net Free/Borrowed Reserves	1560979	1530458	30521	1562421	1543093	1315354

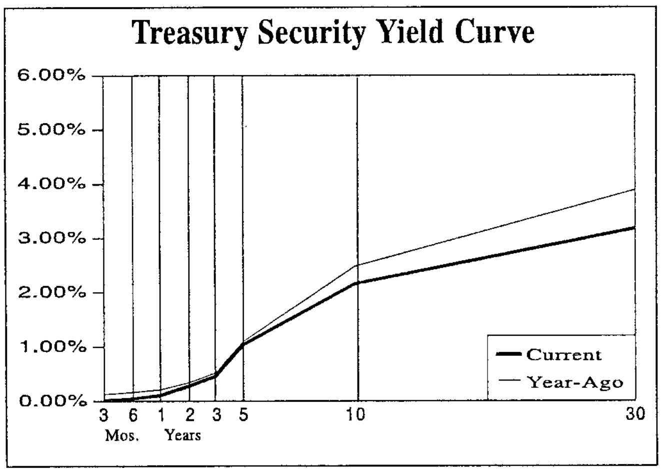
MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/10/11	10/3/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2152.4	2192.5	-40.1	41.1%	30.9%	20.1%
M2 (M1+savings+small time deposits)	9621.4	9604.8	16.6	17.3%	15.8%	10.2%

Selected Yields

	Recent (10/19/11)	3 Months Ago (7/20/11)	Year Ago (10/20/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.44	0.21	0.23
3-month LIBOR	0.41	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.45	0.54
5-year	1.14	1.62	1.61
U.S. Treasury Securities			
3-month	0.02	0.02	0.13
6-month	0.05	0.07	0.17
1-year	0.11	0.16	0.21
5-year	1.04	1.47	1.10
10-year	2.16	2.93	2.48
10-year (inflation-protected)	0.20	0.54	0.42
30-year	3.18	4.25	3.89
30-year Zero	3.38	4.65	4.25
Mortgage-Backed Securities			
GNMA 5.5%	1.84	2.06	1.29
FHLMC 5.5% (Gold)	2.36	2.64	1.68
FNMA 5.5%	2.17	2.55	1.52
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.33	4.45	4.09
Industrial (25/30-year) A	4.53	5.32	5.14
Utility (25/30-year) A	4.40	5.27	5.22
Utility (25/30-year) Baa/BBB	4.92	5.78	5.72
Foreign Bonds (10-Year)			
Canada	2.33	2.95	2.75
Germany	2.06	2.77	2.44
Japan	1.02	1.09	0.90
United Kingdom	2.47	3.07	2.99
Preferred Stocks			
Utility A	5.25	5.12	5.79
Financial A	6.69	6.07	6.59
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.17	4.51	3.82
25-Bond Index (Revs)	5.06	5.30	4.57
General Obligation Bonds (GOs)			
1-year Aaa	0.25	0.20	0.33
1-year A	1.08	1.04	1.11
5-year Aaa	1.39	1.27	1.25
5-year A	2.40	2.34	2.22
10-year Aaa	2.69	2.91	2.56
10-year A	3.67	4.24	3.66
25/30-year Aaa	4.09	4.34	4.17
25/30-year A	5.45	5.85	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.63
Electric AA	4.94	5.19	4.65
Housing AA	5.64	5.80	5.53
Hospital AA	4.97	5.12	4.82
Toll Road Aaa	4.57	4.92	4.62



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	10/5/11	9/21/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1541886	1548766	-6880	1583023	1546301	1316519
Borrowed Reserves	11429	11614	-185	11920	13833	25141
Net Free/Borrowed Reserves	1530457	1537152	-6695	1571103	1532469	1291378

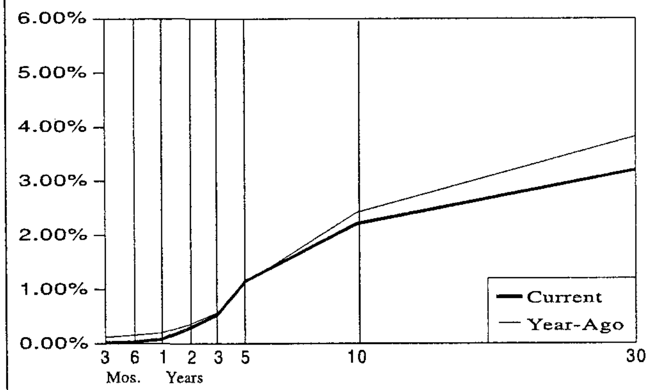
MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/3/11	9/26/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2182.8	2134.4	48.4	43.1%	31.8%	22.6%
M2 (M1+savings+small time deposits)	9617.9	9601.7	16.2	16.8%	15.8%	10.3%

Selected Yields

	Recent (10/12/11)	3 Months Ago (7/13/11)	Year Ago (10/13/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.38	0.23	0.24
3-month LIBOR	0.40	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.32
1-year	0.21	0.44	0.56
5-year	1.14	1.61	1.66
U.S. Treasury Securities			
3-month	0.02	0.03	0.12
6-month	0.04	0.05	0.16
1-year	0.08	0.15	0.20
5-year	1.15	1.44	1.12
10-year	2.21	2.88	2.42
10-year (inflation-protected)	0.23	0.52	0.36
30-year	3.20	4.17	3.82
30-year Zero	3.39	4.55	4.16

Treasury Security Yield Curve



	Recent (10/12/11)	3 Months Ago (7/13/11)	Year Ago (10/13/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.89	2.11	1.27
FHLMC 5.5% (Gold)	2.32	2.66	1.74
FNMA 5.5%	2.17	2.56	1.58
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	4.37	4.37	3.96
Industrial (25/30-year) A	4.59	5.26	5.01
Utility (25/30-year) A	4.53	5.20	5.02
Utility (25/30-year) Baa/BBB	4.99	5.75	5.56
Foreign Bonds (10-Year)			
Canada	2.35	2.93	2.73
Germany	2.19	2.75	2.28
Japan	1.00	1.11	0.88
United Kingdom	2.64	3.12	2.88
Preferred Stocks			
Utility A	5.57	5.22	5.76
Financial A	6.81	6.03	6.38
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.14	4.65	3.84
25-Bond Index (Revs)	5.04	5.36	4.58
General Obligation Bonds (GOs)			
1-year Aaa	0.26	0.20	0.34
1-year A	1.11	1.04	1.14
5-year Aaa	1.41	1.32	1.28
5-year A	2.43	2.40	2.22
10-year Aaa	2.63	2.90	2.58
10-year A	3.75	4.20	3.71
25/30-year Aaa	4.12	4.34	4.15
25/30-year A	5.50	5.85	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.59	4.87	4.61
Electric AA	4.97	5.19	4.63
Housing AA	5.63	5.84	5.50
Hospital AA	5.00	5.13	4.81
Toll Road Aaa	4.60	4.93	4.60

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

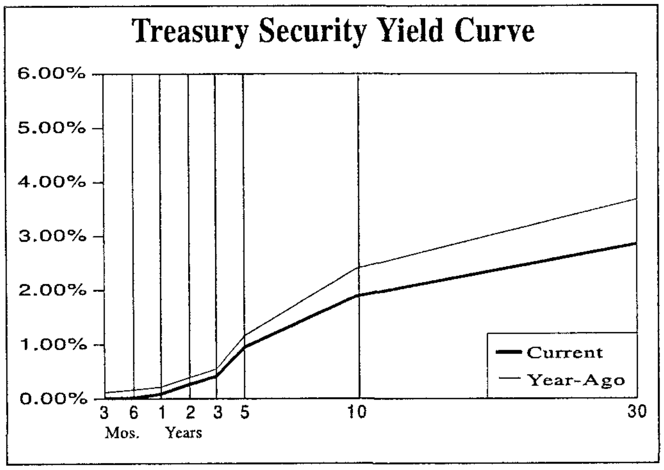
	Recent Levels			Average Levels Over the Last...		
	10/5/11	9/21/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1541919	1548799	-6880	1583036	1546308	1316523
Borrowed Reserves	11429	11614	-185	11920	13833	25141
Net Free/Borrowed Reserves	1530490	1537185	-6695	1571116	1532476	1291381

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/26/11	9/19/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2136.9	2105.7	31.2	44.4%	26.2%	20.6%
M2 (M1+savings+small time deposits)	9603.6	9569.8	33.8	20.6%	16.1%	10.1%

Selected Yields

	Recent (10/05/11)	3 Months Ago (7/06/11)	Year Ago (10/06/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.41	0.18	0.27
3-month LIBOR	0.38	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.33
1-year	0.21	0.44	0.57
5-year	1.18	1.63	1.68
U.S. Treasury Securities			
3-month	0.01	0.01	0.12
6-month	0.02	0.05	0.17
1-year	0.09	0.17	0.22
5-year	0.95	1.66	1.16
10-year	1.89	3.11	2.40
10-year (inflation-protected)	0.08	0.68	0.46
30-year	2.85	4.36	3.68
30-year Zero	3.03	4.75	3.98



	Recent (10/05/11)	3 Months Ago (7/06/11)	Year Ago (10/06/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.54	2.32	1.65
FHLMC 5.5% (Gold)	2.23	2.91	2.16
FNMA 5.5%	2.13	2.81	2.02
FNMA ARM	2.47	2.51	2.86
Corporate Bonds			
Financial (10-year) A	3.88	4.55	3.93
Industrial (25/30-year) A	4.29	5.44	4.92
Utility (25/30-year) A	4.21	5.40	4.91
Utility (25/30-year) Baa/BBB	4.65	5.93	5.45
Foreign Bonds (10-Year)			
Canada	2.14	3.04	2.74
Germany	1.84	2.93	2.22
Japan	0.97	1.18	0.85
United Kingdom	2.36	3.25	2.90
Preferred Stocks			
Utility A	5.29	5.17	6.08
Financial A	6.51	6.03	6.43
Financial Adjustable A	5.48	5.48	5.48
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.93	4.59	3.84
25-Bond Index (Revs)	5.01	5.34	4.59
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.23	0.32
1-year A	0.97	1.02	1.12
5-year Aaa	1.13	1.33	1.33
5-year A	2.18	2.45	2.28
10-year Aaa	2.36	2.75	2.61
10-year A	3.47	4.20	3.77
25/30-year Aaa	3.88	4.39	4.16
25/30-year A	5.53	5.86	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.89	4.62
Electric AA	4.92	5.21	4.63
Housing AA	5.55	5.85	5.52
Hospital AA	4.92	5.25	4.81
Toll Road Aaa	4.58	4.99	4.61

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/21/11	9/7/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1548799	1568587	-19788	1586683	1533774	1295559
Borrowed Reserves	11614	11685	-71	12154	14440	26668
Net Free/Borrowed Reserves	1537185	1556902	-19717	1574529	1519335	1268891

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

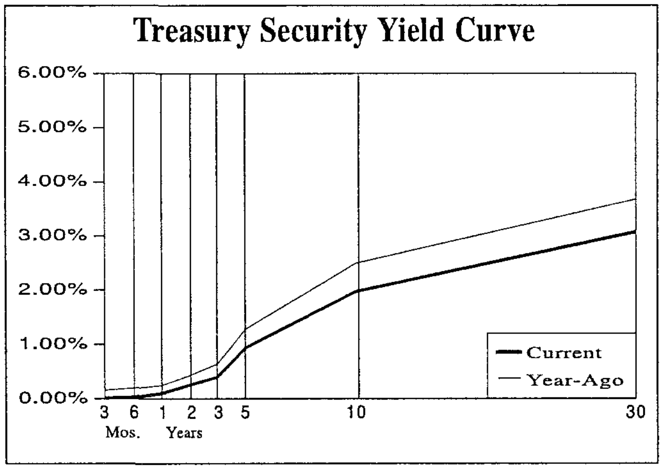
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/19/11	9/12/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2105.7	2106.1	-0.4	38.8%	24.1%	19.2%
M2 (M1+savings+small time deposits)	9569.8	9583.9	-14.1	23.0%	15.2%	10.1%

Selected Yields

TAXABLE

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.42	0.17	0.22
3-month LIBOR	0.37	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.33
1-year	0.21	0.44	0.57
5-year	1.26	1.64	1.68
U.S. Treasury Securities			
3-month	0.01	0.02	0.16
6-month	0.03	0.10	0.19
1-year	0.10	0.19	0.25
5-year	0.94	1.69	1.28
10-year	1.98	3.11	2.50
10-year (inflation-protected)	0.11	0.67	0.69
30-year	3.07	4.38	3.68
30-year Zero	3.28	4.76	3.96

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.62	2.02	2.01
FHLMC 5.5% (Gold)	2.08	2.63	2.33
FNMA 5.5%	1.97	2.50	2.14
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.87	4.58	4.01
Industrial (25/30-year) A	4.50	5.47	4.89
Utility (25/30-year) A	4.34	5.42	4.94
Utility (25/30-year) Baa/BBB	4.98	5.92	5.46
Foreign Bonds (10-Year)			
Canada	2.20	3.09	2.74
Germany	2.01	2.98	2.24
Japan	1.00	1.13	0.93
United Kingdom	2.55	3.33	2.91
Preferred Stocks			
Utility A	5.24	5.13	6.08
Financial A	6.45	6.02	6.50
Financial Adjustable A	5.48	5.48	5.48



TAX-EXEMPT

	Recent (9/28/11)	3 Months Ago (6/29/11)	Year Ago (9/29/10)
Bond Buyer Indexes			
20-Bond Index (GOs)	3.85	4.46	3.83
25-Bond Index (Revs)	4.96	5.31	4.58
General Obligation Bonds (GOs)			
1-year Aaa	0.24	0.24	0.34
1-year A	0.99	1.04	1.15
5-year Aaa	1.04	1.25	1.22
5-year A	2.05	2.41	2.20
10-year Aaa	2.15	2.63	2.51
10-year A	3.42	4.11	3.65
25/30-year Aaa	3.87	4.36	4.11
25/30-year A	5.53	5.86	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.56	4.87	4.61
Electric AA	4.92	5.17	4.62
Housing AA	5.55	5.79	5.49
Hospital AA	4.90	5.25	4.81
Toll Road Aaa	4.58	4.97	4.60

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

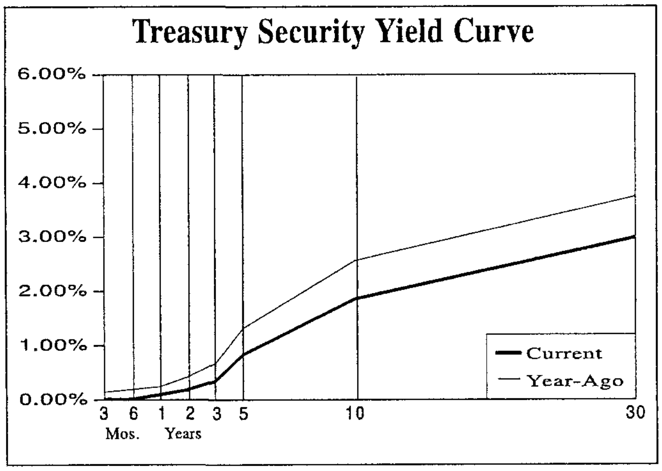
	Recent Levels 9/21/11	9/7/11	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1548803	1568589	-19786	1586684	1533775	1295560
Borrowed Reserves	11614	11685	-71	12154	14440	26668
Net Free/Borrowed Reserves	1537189	1556904	-19715	1574530	1519335	1268892

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 9/12/11	9/5/11	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2106.6	2136.3	-29.7	42.0%	27.6%	18.9%
M2 (M1+savings+small time deposits)	9583.6	9591.1	-7.5	25.4%	15.7%	10.3%

Selected Yields

	Recent (9/21/11)	3 Months Ago (6/22/11)	Year Ago (9/22/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.42	0.18	0.24
3-month LIBOR	0.36	0.25	0.29
Bank CDs			
6-month	0.17	0.26	0.34
1-year	0.21	0.44	0.60
5-year	1.26	1.64	1.71
U.S. Treasury Securities			
3-month	0.01	0.01	0.15
6-month	0.02	0.08	0.19
1-year	0.10	0.15	0.25
5-year	0.84	1.54	1.32
10-year	1.86	2.98	2.56
10-year (inflation-protected)	0.00	0.75	0.65
30-year	2.99	4.22	3.75
30-year Zero	3.25	4.60	4.02



	Recent (9/21/11)	3 Months Ago (6/22/11)	Year Ago (9/22/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.14	2.05	1.99
FHLMC 5.5% (Gold)	1.93	2.55	2.39
FNMA 5.5%	1.85	2.43	2.27
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.59	4.42	4.11
Industrial (25/30-year) A	4.31	5.31	5.02
Utility (25/30-year) A	4.23	5.29	5.04
Utility (25/30-year) Baa/BBB	4.86	5.79	5.56
Foreign Bonds (10-Year)			
Canada	2.12	2.97	2.86
Germany	1.77	2.94	2.35
Japan	0.99	1.12	1.03
United Kingdom	2.41	3.19	2.97
Preferred Stocks			
Utility A	5.23	5.27	6.08
Financial A	6.38	6.10	6.47
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.07	4.49	3.89
25-Bond Index (Revs)	5.11	5.32	4.63
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.28	0.34
1-year A	0.99	1.08	1.15
5-year Aaa	1.00	1.37	1.24
5-year A	1.99	2.40	2.24
10-year Aaa	2.21	2.63	2.56
10-year A	3.56	4.08	3.70
25/30-year Aaa	3.89	4.37	4.11
25/30-year A	5.63	5.89	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.62	4.87	4.61
Electric AA	4.97	5.19	4.62
Housing AA	5.60	5.79	5.44
Hospital AA	4.97	5.28	4.82
Toll Road Aaa	4.69	4.97	4.60

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/7/11	8/24/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1568590	1577802	-9212	1595396	1515698	1275488
Borrowed Reserves	11685	11833	-148	12407	15069	28273
Net Free/Borrowed Reserves	1556905	1565969	-9064	1582989	1500629	1247215

MONEY SUPPLY

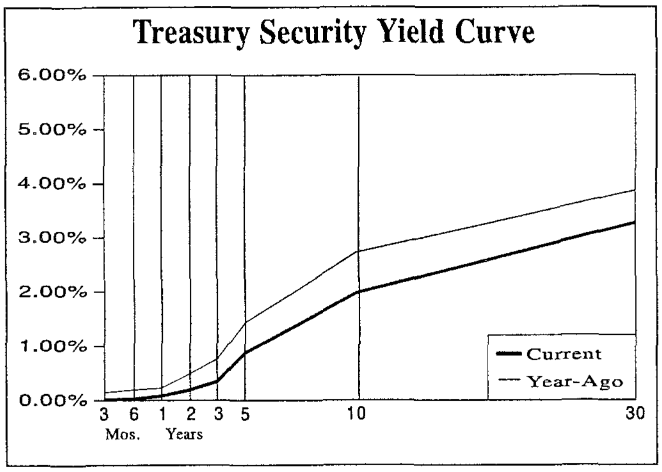
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/5/11	8/29/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2136.6	2124.1	12.5	48.8%	30.8%	21.9%
M2 (M1+savings+small time deposits)	9591.4	9570.1	21.3	26.4%	15.3%	10.5%

Selected Yields

	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.38	0.17	0.24
3-month LIBOR	0.35	0.25	0.29
Bank CDs			
6-month	0.17	0.27	0.35
1-year	0.21	0.45	0.61
5-year	1.29	1.69	1.71
U.S. Treasury Securities			
3-month	0.01	0.05	0.15
6-month	0.03	0.10	0.19
1-year	0.08	0.16	0.23
5-year	0.88	1.55	1.44
10-year	1.98	2.97	2.72
10-year (inflation-protected)	0.06	0.69	0.93
30-year	3.27	4.20	3.87
30-year Zero	3.58	4.57	4.15

	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
Mortgage-Backed Securities			
GNMA 5.5%	1.13	2.11	1.90
FHLMC 5.5% (Gold)	1.97	2.56	2.35
FNMA 5.5%	1.88	2.45	2.17
FNMA ARM	2.50	2.51	2.90
Corporate Bonds			
Financial (10-year) A	3.72	4.84	4.23
Industrial (25/30-year) A	4.60	5.28	5.02
Utility (25/30-year) A	4.48	5.25	5.06
Utility (25/30-year) Baa/BBB	5.07	5.77	5.58
Foreign Bonds (10-Year)			
Canada	2.20	2.95	2.96
Germany	1.88	2.95	2.40
Japan	1.00	1.17	1.05
United Kingdom	2.44	3.24	3.08
Preferred Stocks			
Utility A	5.25	5.77	6.08
Financial A	6.38	6.10	6.81
Financial Adjustable A	5.46	5.46	5.46



	Recent (9/15/11)	3 Months Ago (6/15/11)	Year Ago (9/15/10)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.05	4.49	3.92
25-Bond Index (Revs)	5.07	5.34	4.65
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.25	0.31
1-year A	0.98	1.07	1.14
5-year Aaa	0.93	1.31	1.21
5-year A	1.96	2.40	2.25
10-year Aaa	2.17	2.64	2.45
10-year A	3.65	4.08	3.69
25/30-year Aaa	3.88	4.38	4.06
25/30-year A	5.62	5.89	5.40
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.62	4.87	4.62
Electric AA	4.97	5.18	4.62
Housing AA	5.60	5.59	5.39
Hospital AA	4.97	5.29	4.87
Toll Road Aaa	4.69	4.97	4.60

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/7/11	8/24/11	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1568589	1577800	-9211	1595396	1515698	1275488
Borrowed Reserves	11685	11833	-148	12407	15069	28273
Net Free/Borrowed Reserves	1556904	1565967	-9063	1582989	1500629	1247215

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	8/29/11	8/22/11	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2124.1	2102.8	21.3	38.8%	25.1%	20.8%
M2 (M1+savings+small time deposits)	9570.1	9539.7	30.4	25.7%	15.1%	10.3%

ATTACHMENT D

PINNACLE WEST NYSE-PNW

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
45.43	15.7 (Trailing: 16.3 / Median: 14.0)	1.11	4.6%

VALUE LINE

TIMELINESS 3 Raised 1/29/10

SAFETY 2 Raised 5/6/11

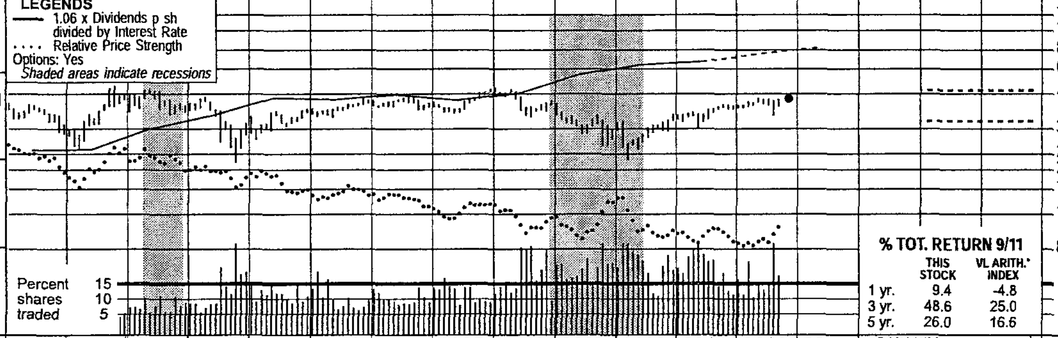
TECHNICAL 3 Lowered 9/16/11

BETA .70 (1.00 = Market)

High:	52.7	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	46.4		
Low:	25.7	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3		

Target Price Range 2014 | 2015 | 2016

LEGENDS
— 1.06 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2014-16 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+10%)	7%
Low	35	(-25%)	Nil

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2010	1Q2011	2Q2011
to Buy	127	126	144
to Sell	151	149	146
Hld's(000)	77797	79145	81484

Percent shares traded 15 10 5

% TOT. RETURN 9/11

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.4	-4.8
3 yr.	48.6	25.0
5 yr.	26.0	16.6

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2009	2010	2011	2012	© VALUE LINE PUB. LLC	14-16
19.28	19.08	20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	32.50	30.01	*29.75*	*31.80*	Revenues per sh	*31.25*
5.09	5.16	5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.08	6.85	*6.80*	*7.55*	"Cash Flow" per sh	*8.00*
1.99	2.22	2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.26	3.08	*2.75*	*3.25*	Earnings per sh A	*3.50*
.83	.93	1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	*2.10*	*2.10*	Div'd Decl'd per sh B ■	*2.30*
2.92	3.38	2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	7.64	7.03	*9.15*	*9.85*	Cap'l Spending per sh	*8.25*
20.32	21.49	22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	32.69	33.86	*34.50*	*35.60*	Book Value per sh C	*39.25*
87.43	87.52	87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	101.43	108.77	*109.25*	*110.00*	Common Shs Outst'g D	*123.00*
9.6	10.8	11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	13.7	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*12.0*
.63	.72	.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.91	.80	*Value Line*		Relative P/E Ratio	*.80*
4.3%	3.9%	3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.8%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*5.5%*

CAPITAL STRUCTURE as of 6/30/11
Total Debt $3672.5 mill. **Due in 5 Yrs** $2071.2 mill.
LT Debt $2761.7 mill. **LT Interest** $167.1 mill.
Incl. $83.1 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $24.0 mill.
Pension Assets-12/10 $1.78 bill. **Oblig.** $2.35 bill.

Pfd Stock None

Common Stock 109,110,950 shs.
as of 7/26/11
MARKET CAP: $5.0 billion (Large Cap)

2000	2001	2002	2003	2004	2005	2006	2007	2009	2010	2011	2012		14-16
3690.2	4551.4	2637.3	2817.9	2899.7	2988.0	3401.7	3523.6	3297.1	3263.6	*3250*	*3500*	Revenues ($mill)	*3850*
283.6	312.2	215.2	230.6	235.2	223.2	317.1	298.8	229.2	330.4	*300*	*360*	Net Profit ($mill)	*430*
44.1%	40.6%	39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	36.9%	31.9%	*34.0%*	*34.5%*	Income Tax Rate	*34.5%*
7.6%	15.3%	20.5%	6.2%	6.9%	10.4%	11.1%	14.8%	11.2%	11.7%	*13.0%*	*13.0%*	AFUDC % to Net Profit	*9.0%*
45.1%	51.7%	51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	50.4%	45.3%	*49.0%*	*52.0%*	Long-Term Debt Ratio	*46.0%*
54.9%	48.3%	48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	49.6%	54.7%	*51.0%*	*48.0%*	Common Equity Ratio	*54.0%*
4337.8	5172.4	5567.9	5727.5	5535.2	6033.4	6678.7	6658.7	6686.6	6729.1	*7415*	*8150*	Total Capital ($mill)	*8950*
5133.2	5907.3	6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	9257.8	9578.8	*10135*	*10750*	Net Plant ($mill)	*12200*
8.1%	7.6%	5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	4.8%	6.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.5%*
11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
11.9%	12.5%	8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.9%	9.0%	*8.0%*	*9.0%*	Return on Com Equity E	*9.0%*
6.8%	7.3%	2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	.7%	3.1%	*2.0%*	*3.5%*	Retained to Com Eq	*3.0%*
43%	41%	64%	68%	71%	85%	63%	70%	89%	66%	*76%*	*64%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2008	2009	2010
% Change Retail Sales (KWH)	-1.3	-2.2	-1.6
Avg. Indust. Use (MWH)	665	619	619
Avg. Indust. Revs. per KWH (¢)	7.91	8.11	7.83
Capacity at Peak (Mw)	8457	8635	8682
Peak Load, Summer (Mw)	7026	7218	6396
Annual Load Factor (%)	51.2	49.3	50.0
% Change Customers (yr-end)	+.9	+.5	+.4
Fixed Charge Cov. (%)	221	248	296

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '08-'10 to '14-'16
Revenues	--	.5%	*-.5%*
"Cash Flow"	--	3.0%	*.5%*
Earnings	-2.5%	.5%	*6.0%*
Dividends	4.5%	3.0%	*1.5%*
Book Value	2.5%	.5%	*2.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	709.8	898.0	1072.9	686.4	3367.1
2009	625.9	836.0	1142.2	693.0	3297.1
2010	620.3	820.6	1139.1	683.6	3263.6
2011	659.6	799.8	*1100*	*690.6*	*3250*
2012	*675*	*850*	*1250*	*725*	*3500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	d.04	1.13	1.50	d.48	2.12
2009	d.36	.74	2.07	d.19	2.26
2010	.07	.83	2.08	.06	3.08
2011	d.14	.78	*2.06*	*.05*	*2.75*
2012	*Nil*	*.95*	*2.25*	*.05*	*3.25*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	.525	.525	.525	.525	2.10
2008	.525	.525	.525	.525	2.10
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525		

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in 11 of 15 Arizona counties. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 47%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 37%; nuclear, 27%; gas, 12%; purchased, 24%. Fuel costs: 36% of revenues. Has 7,200 employees. '09 reported depreciation rate: 3.1%. Chairman, President & Chief Executive Officer: Donald E. Brandt. Incorporated: Arizona. Address: 400 North Fifth Street, Post Office Box 53999, Phoenix, Arizona 85072-3999. Telephone: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary has a general rate case pending. Arizona Public Service filed for a tariff hike of $194.1 million (6.6%), based on a return of 11% on a common-equity ratio of 53.9%. APS is asking for a regulatory mechanism that decouples electric volume and revenues, and a tracker that raises rates annually to recover infrastructure additions for generating assets and environmental compliance. The utility also wants to revise the fuel adjustment clause so that it accounts for all changes in fuel costs, not just 90% of them. (Other utilities in the state have 100% pass-through of fuel costs.) New tariffs won't take effect until mid-2012, at the earliest. Settlement talks will begin in the next several weeks.

Milder-than-normal weather conditions have prompted us to cut our 2011 earnings estimate. We reduced our estimate by $0.30 a share, to $2.75. That's at the low end of the company's guidance of $2.75-$2.90 a share. We continue to forecast share net of $3.25 in *2012*, assuming APS receives a decent rate order and weather patterns return to normal.

The utility is awaiting regulatory approval for an asset acquisition. APS has agreed to pay $294 million for Southern California Edison's 739-megawatt stake in units 4 and 5 of the Four Corners coal-fired plant. The company would finance the purchase with a mix of debt and equity. APS would have to spend $300 million on environmental upgrades, but would be able to avoid more than $600 million needed for units 1, 2, and 3, which would be shut down. The transaction is expected to close in late 2012. Our figures will not reflect the deal until after it has been completed.

APS is adding solar capacity. In the first phase, it plans to build 100 mw at a cost of up to $500 million. APS has procured 83 mw, so far, at a cost of $384 million. The utility is proposing to add 100 mw more for up to $475 million.

This stock's yield isn't high enough to compensate investors for low dividend growth potential. Not only is the share price within our 3- to 5-year Target Price Range, *it remains closer to the high* end than the low end. Thus, total return potential over that time frame is modest.

Paul E. Debbas, CFA *November 4, 2011*

(A) Diluted egs. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 1¢. '08 EPS don't add due to rounding, '10 due to change in shares. Next earnings report due mid-Feb. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '10: $11.28/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '10: 11%; earned on avg. com. eq., '10: 9.5%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	65

ZACKS
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Proven Ratings, Research & Recommendations
Zacks.com Quotes and Research

PINNACLE WEST CAP CORP (NYSE)

ZACKS RANK: 2 - BUY

PNW 46.32 ▲0.07 (0.15%) Vol. 490,177 16:01 ET

Pinnacle West Capital is engaged, through its subsidiaries, in the generation, transmission, and distribution of electricity and selling energy, products and services; in real estate development; and in venture capital investment. Its primary subsidiary is Arizona Public Service Company. The company's other subsidiaries include SunCor, El Dorado, APSEnergy Services and Pinnacle West Energy.

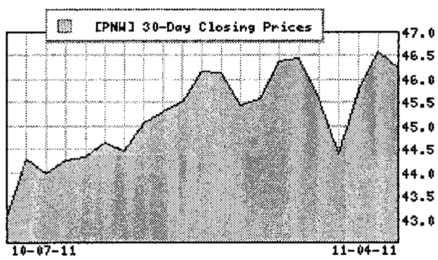
General Information

PINNACLE WEST
400 NORTH FIFTH STREET
PHOENIX, AZ 85004
Phone: 6022501000
Fax: 602-250-2430
Web: http://www.pinnaclewest.com
Email: rhickman@pinnaclewest.com

Industry	UTIL-ELEC PWR
Sector:	Utilities
Fiscal Year End	December
Last Completed Quarter	09/30/11
Next EPS Date	02/17/2012

Price and Volume Information

Zacks Rank	
Yesterday's Close	46.25
52 Week High	47.36
52 Week Low	37.28
Beta	0.55
20 Day Moving Average	1,239,555.88
Target Price Consensus	46



% Price Change		% Price Change Relative to S&P 500	
4 Week	7.41	4 Week	-0.97
12 Week	12.72	12 Week	6.03
YTD	11.58	YTD	11.97

Share Information		Dividend Information	
Shares Outstanding (millions)	109.11	Dividend Yield	4.54%
		Annual Dividend	$2.10
Market Capitalization (millions)	5,046.38	Payout Ratio	0.69
Short Ratio	2.03	Change in Payout Ratio	-0.12
Last Split Date	N/A	Last Dividend Payout / Amount	10/28/2011 / $0.52

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.04	Current (1=Strong Buy, 5=Strong Sell)	2.73
Current Year EPS Consensus Estimate	2.88	30 Days Ago	2.73
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.75
Next EPS Report Date	02/17/2012	90 Days Ago	2.75

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.08	vs. Previous Year	7.69%	vs. Previous Year	-1.25%
Trailing 12 Months:	15.21	vs. Previous Quarter	187.18%	vs. Previous Quarter:	40.64%
PEG Ratio	3.02				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.26	09/30/11	8.80	09/30/11	2.66

Price/Cash Flow	7.31	06/30/11	8.40	06/30/11	2.55
Price / Sales	1.54	03/31/11	8.57	03/31/11	2.60
Current Ratio		**Quick Ratio**		**Operating Margin**	
09/30/11	0.89	09/30/11	0.76	09/30/11	10.25
06/30/11	0.57	06/30/11	0.45	06/30/11	9.62
03/31/11	0.57	03/31/11	0.46	03/31/11	9.68
Net Margin		**Pre-Tax Margin**		**Book Value**	
09/30/11	16.14	09/30/11	16.14	09/30/11	36.69
06/30/11	15.07	06/30/11	15.07	06/30/11	34.08
03/31/11	14.99	03/31/11	14.99	03/31/11	34.28
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
09/30/11	9.27	09/30/11	0.76	09/30/11	43.22
06/30/11	9.77	06/30/11	0.74	06/30/11	42.64
03/31/11	10.07	03/31/11	0.76	03/31/11	43.28

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224
TABLE OF CONTENTS TO SCHEDULES WAR

ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITALIZATION PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED CAPITALIZATION	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	3,382,856	-	3,382,856	46.06%	6.26%	2.88%
3	COMMON EQUITY	3,961,248	-	3,961,248	53.94%	10.00%	5.39%
4	TOTAL CAPITALIZATION	$ 7,344,104	$ -	$ 7,344,104	100.00%		
5	ORIGINAL COST WEIGHTED AVERAGE COST OF CAPITAL						8.27%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 17
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 7
COLUMN (F): COLUMN (D) x COLUMN (E)

FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL

LINE NO.		(A) CAPITALIZATION	(B) RUCO	(C) RUCO ADJUSTED	(D) CAPITAL	(E)	(F) WEIGHTED
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	3,382,856	-	3,382,856	46.06%	4.08%	1.88%
3	COMMON EQUITY	3,961,248	-	3,961,248	53.94%	7.82%	4.22%
4	TOTAL CAPITALIZATION	$ 7,344,104	$ -	$ 7,344,104	100.00%		
5	FAIR VALUE WEIGHTED AVERAGE COST OF CAPITAL						6.10%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - COMPANY SCHEDULE D-1
COLUMN (E): LINE 2 - SCHEDULE WAR-1, PAGE 2 LINE 19
COLUMN (E): LINE 3 - SCHEDULE WAR-1, PAGE 3 LINE 9
COLUMN (F): COLUMN (D) x COLUMN (E)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
COST OF CAPITAL SUMMARY

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 1

COST OF DEBT

LINE NO.	DESCRIPTION	(A) MATURITY DATES	(B) BALANCE AS OF DECEMBER 31, 2008	(C) RUCO ADJUSTMENT	(D) RUCO ADJUSTED BALANCE	(E) COST	(F) INTEREST	
1	POLLUTION CONTROL BONDS - VARIABLE	2024-2038	$ 43,580	$ -	$ 43,580	0.320%	$ 139	
2	POLLUTION CONTROL BONDS - FIXED	2029-2034	522,275	-	522,275	5.701%	29,774	
3	POLLUTION CONTROL BONDS WITH SENIOR NOTES	2029	90,000	-	90,000	5.050%	4,545	
4	UNSECURED NOTES	2011	400,000	-	400,000	6.375%	25,500	
5	UNSECURED NOTES	2012	375,000	-	375,000	6.500%	24,375	
6	UNSECURED NOTES	2014	300,000	-	300,000	5.800%	17,400	
7	UNSECURED NOTES	2015	300,000	-	300,000	4.650%	13,950	
8	UNSECURED NOTES	2016	250,000	-	250,000	6.250%	15,625	
9	UNSECURED NOTES	2019	500,000	-	500,000	8.750%	43,750	
10	UNSECURED NOTES	2033	200,000	-	200,000	5.625%	11,250	
11	UNSECURED NOTES	2035	250,000	-	250,000	5.500%	13,750	
12	UNSECURED NOTES	2036	150,000	-	150,000	6.875%	10,313	
13	CAPITALIZED LEASE OBLIGATIONS	2011-2012	2,001	-	2,001	5.297%	106	
14	OTHER		-	-	-	0.000%	1,286	
15								
16	TOTALS		$ 3,382,856	$ -	$ 3,382,856		$ 211,763	
17	**COST OF LONG-TERM DEBT - ORIGINAL COST**						**6.26%**	COLUMN (F), LINE 16 / COLUMN (D), LINE 16
18	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**						**2.18%**	SCHEDULE WAR-1, PAGE 4, COLUMN (D), LINE 11
19	**COST OF LONG-TERM DEBT - FAIR VALUE**						$\boxed{\textbf{4.08\%}}$	LINE 8 - LINE 9

REFERENCES:
COLUMNS (A) AND (B): COMPANY FORM 10-K FILED ON 02/18/2011, COMPANY SCHEDULE D-2, PAGE 1 OF 1
COLUMN (C): TESTIMONY WAR
COLUMN (D): COLUMN (B) - COLUMN (C)
COLUMN (E): LINES 1 THROUGH 14 / LINE 16
COLUMN (F): COMPANY FORM 10-K FILED ON 02/18/2011, SCHEDULE E-9

COST OF COMMON EQUITY ESTIMATE

LINE NO.			
1	DCF METHODOLOGY		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.77%	SCHEDULE WAR-2, COLUMN (C), LINE 10
3	CAPM METHODOLOGY		
4	CAPM - GEOMETRIC MEAN ESTIMATE	3.83%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 10
5	CAPM - ARITHMETIC MEAN ESTIMATE	5.09%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 10
6	AVERAGE OF CAPM ESTIMATES	4.46%	(LINE 4 + LINE 5) / 2
7	**COST OF COMMON EQUITY ESTIMATE - ORIGINAL COST**	**10.00%**	TESTIMONY, WAR
8	**LESS: RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**	**2.18%**	SCHEDULE WAR-1, PAGE 4, COLUMN (D), LINE 11
9	**COST OF COMMON EQUITY ESTIMATE - FAIR VALUE**	$\boxed{7.82\%}$	LINE 8 - LINE 9

INFLATION ADJUSTMENT TO RUCO'S RECOMMENDED ORIGINAL COST OF EQUITY CAPITAL

LINE NO.	(A) YEAR	(B) VALUE TIPS	(C) VALUE BONDS	(D) DIFFERENCE
1	2003	2.06%	4.01%	1.95%
2	2004	1.83%	4.27%	2.44%
3	2005	1.82%	4.29%	2.47%
4	2006	2.31%	4.80%	2.49%
5	2007	2.29%	4.64%	2.35%
6	2008	1.76%	3.67%	1.91%
7	2009	1.66%	3.26%	1.60%
8	2010	1.15%	3.22%	2.07%
9	2011	1.05%	3.36%	2.31%
10	AVERAGE	1.77%	3.95%	2.18%
11	**RECOMMENDED FAIR VALUE INFLATION ADJUSTMENT**			**2.18%**

REFERENCES

COLUMNS (A) THRU (C), LINES 1 THRU 9: FEDERAL RESERVE BANK OF ST. LOUIS WEBSITE
COLUMN (D): COLUMN (C) - COLUMN (D)
COLUMNS (B) THRU (D), LINE 10: AVERAGE OF LINES 1 THRU 9
COLUMN (D), LINE 11: TESTIMONY - WAR

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DCF COST OF EQUITY CAPITAL

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) DIVIDEND YIELD		(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AEE	AMEREN CORP.	5.05%	+	5.75%	=	10.81%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.81%	+	4.72%	=	9.54%
3	CNP	CENTERPOINT ENERGY, INC.	3.93%	+	4.15%	=	8.08%
4	CNL	CLECO CORPORATION	3.18%	+	5.04%	=	8.22%
5	CMS	CMS ENERGY CORPORATION	4.21%	+	5.30%	=	9.50%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	2.51%	+	6.34%	=	8.84%
7	DTE	DTE ENERGY COMPANY	4.67%	+	3.25%	=	7.92%
8	EIX	EDISON INTERNATIONAL	3.35%	+	4.50%	=	7.85%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	4.16%	+	12.61%	=	16.76%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	5.02%	+	3.56%	=	8.58%
11	IDA	IDACORP, INC.	3.07%	+	5.35%	=	8.42%
12	TEG	INTEGRYS ENERGY GROUP, INC.	5.45%	+	3.12%	=	8.57%
13	ITC	ITC HOLDINGS CORP.	1.90%	+	12.34%	=	14.24%
14	POM	PEPCO HOLDINGS INC.	5.65%	+	2.10%	=	7.76%
15	PCG	PG&E CORPORATION	4.32%	+	5.82%	=	10.14%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.42%	+	4.21%	=	8.63%
17	PPL	PPL CORPORATION	4.88%	+	7.98%	=	12.85%
18	TE	TECO ENERGY, INC.	4.83%	+	5.27%	=	10.10%
19	WR	WESTAR ENERGY, INC.	4.80%	+	4.16%	=	8.96%
20	WEC	WISCONSIN ENERGY CORPORATION	3.28%	+	6.25%	=	9.53%
21	**AVERAGE**						**9.77%**
22							

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND (PER SHARE)	/	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	AEE	AMEREN CORP.	$ 1.54	/	$ 30.47	=	5.05%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	1.84	/	38.22	=	4.81%
3	CNP	CENTERPOINT ENERGY, INC.	0.79	/	20.11	=	3.93%
4	CNL	CLECO CORPORATION	1.12	/	35.22	=	3.18%
5	CMS	CMS ENERGY CORPORATION	0.84	/	19.98	=	4.21%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	0.96	/	38.31	=	2.51%
7	DTE	DTE ENERGY COMPANY	2.35	/	50.28	=	4.67%
8	EIX	EDISON INTERNATIONAL	1.28	/	38.23	=	3.35%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	0.83	/	19.97	=	4.16%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	1.24	/	24.70	=	5.02%
11	IDA	IDACORP, INC.	1.20	/	39.04	=	3.07%
12	TEG	INTEGRYS ENERGY GROUP, INC.	2.72	/	49.87	=	5.45%
13	ITC	ITC HOLDINGS CORP.	1.41	/	74.16	=	1.90%
14	POM	PEPCO HOLDINGS INC.	1.08	/	19.10	=	5.65%
15	PCG	PG&E CORPORATION	1.82	/	42.12	=	4.32%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	1.06	/	23.98	=	4.42%
17	PPL	PPL CORPORATION	1.40	/	28.71	=	4.88%
18	TE	TECO ENERGY, INC.	0.86	/	17.81	=	4.83%
19	WR	WESTAR ENERGY, INC.	1.28	/	26.65	=	4.80%
20	WEC	WISCONSIN ENERGY CORPORATION	1.04	/	31.75	=	3.28%
21	**AVERAGE**						**4.17%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AEE	AMEREN CORP.	3.00%	+	2.75%	=	5.75%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.60%	+	0.12%	=	4.72%
3	CNP	CENTERPOINT ENERGY, INC.	4.00%	+	0.15%	=	4.15%
4	CNL	CLECO CORPORATION	5.00%	+	0.04%	=	5.04%
5	CMS	CMS ENERGY CORPORATION	5.00%	+	0.30%	=	5.30%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	5.25%	+	1.09%	=	6.34%
7	DTE	DTE ENERGY COMPANY	3.20%	+	0.05%	=	3.25%
8	EIX	EDISON INTERNATIONAL	4.50%	+	0.00%	=	4.50%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	2.80%	+	9.81%	=	12.61%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.00%	+	0.56%	=	3.56%
11	IDA	IDACORP, INC.	5.25%	+	0.10%	=	5.35%
12	TEG	INTEGRYS ENERGY GROUP, INC.	3.00%	+	0.12%	=	3.12%
13	ITC	ITC HOLDINGS CORP.	10.25%	+	2.09%	=	12.34%
14	POM	PEPCO HOLDINGS INC.	2.10%	+	0.00%	=	2.10%
15	PCG	PG&E CORPORATION	5.30%	+	0.52%	=	5.82%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.20%	+	0.01%	=	4.21%
17	PPL	PPL CORPORATION	5.50%	+	2.48%	=	7.98%
18	TE	TECO ENERGY, INC.	5.10%	+	0.17%	=	5.27%
19	WR	WESTAR ENERGY, INC.	3.75%	+	0.41%	=	4.16%
20	WEC	WISCONSIN ENERGY CORPORATION	6.25%	+	0.00%	=	6.25%
21	**AVERAGE**						**5.59%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH	(B) x { [((M ÷ B) + 1) ÷ 2] - 1 } =	(C) EXTERNAL GROWTH (sv)
1	AEE	AMEREN CORP.	1.40%	x { [((0.93) + 1) ÷ 2] + 1 } =	2.75%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	0.85%	x { [((1.29) + 1) ÷ 2] - 1 } =	0.12%
3	CNP	CENTERPOINT ENERGY, INC.	0.30%	x { [((2.03) + 1) ÷ 2] - 1 } =	0.15%
4	CNL	CLECO CORPORATION	0.15%	x { [((1.49) + 1) ÷ 2] - 1 } =	0.04%
5	CMS	CMS ENERGY CORPORATION	0.90%	x { [((1.66) + 1) ÷ 2] - 1 } =	0.30%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	0.55%	x { [((0.95) + 1) ÷ 2] + 1 } =	1.09%
7	DTE	DTE ENERGY COMPANY	0.40%	x { [((1.23) + 1) ÷ 2] - 1 } =	0.05%
8	EIX	EDISON INTERNATIONAL	0.01%	x { [((1.13) + 1) ÷ 2] - 1 } =	0.00%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	5.00%	x { [((0.92) + 1) ÷ 2] + 1 } =	9.81%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2.00%	x { [((1.56) + 1) ÷ 2] - 1 } =	0.56%
11	IDA	IDACORP, INC.	1.00%	x { [((1.20) + 1) ÷ 2] - 1 } =	0.10%
12	TEG	INTEGRYS ENERGY GROUP, INC.	0.75%	x { [((1.32) + 1) ÷ 2] - 1 } =	0.12%
13	ITC	ITC HOLDINGS CORP.	2.00%	x { [((3.09) + 1) ÷ 2] - 1 } =	2.09%
14	POM	PEPCO HOLDINGS INC.	1.75%	x { [((1.01) + 1) ÷ 2] - 1 } =	0.00%
15	PCG	PG&E CORPORATION	2.50%	x { [((1.41) + 1) ÷ 2] - 1 } =	0.52%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	0.30%	x { [((1.09) + 1) ÷ 2] - 1 } =	0.01%
17	PPL	PPL CORPORATION	10.00%	x { [((1.50) + 1) ÷ 2] - 1 } =	2.48%
18	TE	TECO ENERGY, INC.	0.50%	x { [((1.69) + 1) ÷ 2] - 1 } =	0.17%
19	WR	WESTAR ENERGY, INC.	3.50%	x { [((1.23) + 1) ÷ 2] - 1 } =	0.41%
20	WEC	WISCONSIN ENERGY CORPORATION	0.01%	x { [((1.86) + 1) ÷ 2] - 1 } =	0.00%
21	**AVERAGE**				**1.04%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	AEE	AMEREN CORP.	2006	0.1477	8.10%	1.20%	31.86	206.60	
2			2007	0.1477	9.20%	1.36%	32.41	208.30	
3			2008	0.1181	8.70%	1.03%	32.80	212.30	
4			2009	0.4460	7.80%	3.48%	33.08	237.40	
5			2010	0.4440	8.60%	3.82%	32.15	240.40	
6			GROWTH 2006 - 2010			2.18%	2.50%		3.65%
7			2011	0.3583	7.00%	2.51%		244.00	1.50%
8			2012	0.3583	7.00%	2.51%		247.00	1.36%
9			2014-16	0.3840	7.00%	2.69%	1.50%	256.00	1.27%
10									
11	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	2006	0.4755	12.00%	5.71%	23.73	396.67	
12			2007	0.4476	11.40%	5.10%	25.17	400.43	
13			2008	0.4515	11.30%	5.10%	26.33	406.07	
14			2009	0.4478	10.40%	4.66%	27.49	478.05	
15			2010	0.3423	9.10%	3.12%	28.33	480.81	
16			GROWTH 2006 - 2010			4.49%	5.00%		4.93%
17			2011	0.4159	10.50%	4.37%		485.00	0.87%
18			2012	0.4154	10.50%	4.36%		489.00	0.85%
19			2014-16	0.4400	10.50%	4.62%	4.50%	500.00	0.79%
20									
21	CNP	CENTERPOINT ENERGY, INC.	2006	0.5489	27.80%	15.26%	4.96	313.65	
22			2007	0.4188	22.00%	9.21%	5.61	322.72	
23			2008	0.4385	21.90%	9.60%	5.89	346.09	
24			2009	0.2475	14.10%	3.49%	6.74	391.75	
25			2010	0.2710	13.80%	3.74%	7.53	424.70	
26			GROWTH 2006 - 2010			8.26%	8.50%		7.87%
27			2011	0.3417	12.00%	4.10%		426.00	0.31%
28			2012	0.3333	12.00%	4.00%		427.00	0.27%
29			2014-16	0.3333	11.50%	3.83%	10.00%	430.00	0.25%
30									
31	CNL	CLECO CORPORATION	2006	0.3382	8.30%	2.81%	15.22	57.57	
32			2007	0.3182	7.80%	2.48%	16.85	59.94	
33			2008	0.4706	9.60%	4.52%	17.65	60.04	
34			2009	0.4886	9.50%	4.64%	18.50	60.26	
35			2010	0.5721	10.60%	6.06%	21.76	60.53	
36			GROWTH 2006 - 2010			3.97%	11.00%		1.26%
37			2011	0.5458	10.00%	5.46%		60.70	0.28%
38			2012	0.4917	10.00%	4.92%		60.70	0.14%
39			2014-16	0.4182	9.50%	3.97%	6.50%	60.70	0.06%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	CMS	CMS ENERGY CORPORATION	2006	NMF	6.40%	NMF	10.03	222.78	
2			2007	0.6875	7.20%	4.95%	9.46	225.15	
3			2008	0.7073	11.70%	8.28%	10.88	226.41	
4			2009	0.4624	8.50%	3.93%	11.42	227.89	
5			2010	0.5038	12.50%	6.30%	11.19	249.60	
6			GROWTH 2006 - 2010			5.86%	1.50%		2.88%
7			2011	0.4207	12.50%	5.26%		252.00	0.96%
8			2012	0.4065	12.50%	5.08%		254.00	0.88%
9			2014-16	0.3714	12.50%	4.64%	5.00%	260.00	0.82%
10									
11	CEG	CONSTELLATION ENERGY GROUP, INC.	2006	0.5984	14.80%	8.86%	25.53	180.52	
12			2007	0.5944	14.70%	8.74%	29.93	178.44	
13			2008	-2.9792	2.70%	NMF	15.98	199.13	
14			2009	0.4637	4.10%	1.90%	43.27	200.99	
15			2010	0.4037	4.10%	1.66%	39.19	199.79	
16			GROWTH 2006 - 2010			5.29%	4.50%		2.57%
17			2011	0.5826	6.00%	3.50%		201.00	0.61%
18			2012	0.5826	5.50%	3.20%		202.00	0.55%
19			2014-16	0.7143	7.50%	5.36%	6.50%	205.00	0.52%
20									
21	DTE	DTE ENERGY COMPANY	2006	0.1510	7.50%	1.13%	33.02	177.14	
22			2007	0.2030	7.70%	1.56%	35.86	163.23	
23			2008	0.2234	7.40%	1.65%	36.77	163.02	
24			2009	0.3457	8.50%	2.94%	37.96	165.40	
25			2010	0.4171	9.40%	3.92%	39.67	169.43	
26			GROWTH 2006 - 2010			2.74%	3.50%		-1.11%
27			2011	0.3556	9.00%	3.20%		169.50	0.04%
28			2012	0.3547	9.00%	3.19%		170.00	0.17%
29			2014-16	0.3647	9.00%	3.28%	3.50%	174.00	0.53%
30									
31	EIX	EDISON INTERNATIONAL	2006	0.6646	14.00%	9.30%	23.66	325.81	
32			2007	0.6446	13.00%	8.38%	25.92	325.81	
33			2008	0.6658	12.80%	8.52%	29.21	325.81	
34			2009	0.6142	10.80%	6.63%	30.20	325.81	
35			2010	0.6209	10.40%	6.46%	32.44	325.81	
36			GROWTH 2006 - 2010			7.86%	1.05%		0.00%
37			2011	0.5309	8.00%	4.25%		325.81	0.00%
38			2012	0.5321	8.50%	4.52%		325.81	0.00%
39			2014-16	0.5692	8.00%	4.55%	0.55%	325.81	0.00%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS
DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	GXP	GREAT PLAINS ENERGY INCORPORATED	2006	-0.0247		9.40%		NMF	16.70	80.35	
2			2007	0.1075		10.10%		1.09%	18.18	86.23	
3			2008	-0.4310		4.60%		NMF	21.39	119.26	
4			2009	0.1942		4.80%		0.93%	20.62	135.42	
5			2010	0.4575		7.30%		3.34%	21.26	135.71	
6			GROWTH 2006 - 2010					1.79%	7.00%		14.00%
7			2011	0.3083		5.50%		1.70%		136.00	0.21%
8			2012	0.4276		6.50%		2.78%		155.00	6.87%
9			2014-16	0.3714		7.50%		2.79%	2.00%	155.00	2.69%
10											
11	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	2006	0.0677		9.90%		0.67%	13.44	81.46	
12			2007	-0.1171		7.20%		NMF	15.29	83.43	
13			2008	-0.1589		6.50%		NMF	15.35	90.52	
14			2009	-0.3626		5.80%		NMF	15.58	92.52	
15			2010	-0.0248		7.70%		NMF	15.67	94.69	
16			GROWTH 2006 - 2010					0.67%	1.00%		3.83%
17			2011	0.0462		8.00%		0.37%		96.00	1.38%
18			2012	0.1448		9.00%		1.30%		96.00	0.69%
19			2014-16	0.3500		10.50%		3.68%	2.50%	108.00	2.67%
20											
21	IDA	IDACORP, INC.	2006	0.4894		8.90%		4.36%	25.77	43.63	
22			2007	0.3548		6.80%		2.41%	26.79	45.06	
23			2008	0.4495		7.60%		3.42%	27.76	46.92	
24			2009	0.5455		8.90%		4.85%	29.17	47.90	
25			2010	0.5932		9.30%		5.52%	31.01	49.41	
26			GROWTH 2006 - 2010					4.11%	4.50%		3.16%
27			2011	0.6129		9.50%		5.82%		50.00	1.19%
28			2012	0.6066		9.00%		5.46%		50.50	1.10%
29			2014-16	0.5455		8.50%		4.64%	5.00%	51.00	0.64%
30											
31	TEG	INTEGRYS ENERGY GROUP, INC.	2006	0.3504		9.70%		3.40%	35.61	43.06	
32			2007	-0.0323		5.50%		NMF	42.58	75.99	
33			2008	-0.6962		3.90%		NMF	40.79	75.99	
34			2009	-0.1930		6.10%		NMF	37.62	75.98	
35			2010	0.1605		8.70%		1.40%	37.57	77.35	
36			GROWTH 2006 - 2010					2.40%	5.50%		15.77%
37			2011	0.1758		9.00%		1.58%		78.30	1.23%
38			2012	0.2229		9.00%		2.01%		78.30	0.61%
39			2014-16	0.3200		9.50%		3.04%	1.50%	78.30	0.24%

REFERENCES:
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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b) x	(B) RETURN ON BOOK EQUITY (r) =	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ITC	ITC HOLDINGS CORP.	2006	-0.1739	6.20%	NMF	12.55	42.40	
2			2007	0.3274	13.00%	4.26%	13.12	42.92	
3			2008	0.4566	11.80%	5.39%	18.71	49.65	
4			2009	0.5155	12.90%	6.65%	20.20	50.08	
5			2010	0.5387	13.00%	7.00%	22.03	50.72	
6			GROWTH 2006 - 2010			5.82%	-		4.58%
7			2011	0.5818	13.50%	7.85%		52.00	4.58%
8			2012	0.6286	14.50%	9.11%		52.75	2.52%
9			2014-16	0.6909	15.50%	10.71%	10.50%	55.00	1.98%
10									
11	POM	PEPCO HOLDINGS INC.	2006	0.2180	7.00%	1.53%	18.82	191.93	
12			2007	0.3203	7.40%	2.37%	20.04	200.51	
13			2008	0.4404	9.50%	4.18%	19.14	218.91	
14			2009	-0.0189	5.50%	NMF	19.15	222.27	
15			2010	0.1290	6.50%	0.84%	18.79	225.08	
16			GROWTH 2006 - 2010			2.23%	1.00%		4.06%
17			2011	0.1360	6.50%	0.88%		227.00	0.85%
18			2012	0.1360	6.00%	0.82%		235.00	2.18%
19			2014-16	0.2970	7.50%	2.23%	2.00%	250.00	2.12%
20									
21	PCG	PG&E CORPORATION	2006	0.5217	12.70%	6.63%	22.44	348.14	
22			2007	0.4820	11.80%	5.69%	24.18	353.72	
23			2008	0.5155	12.60%	6.50%	25.97	361.06	
24			2009	0.4455	11.20%	4.99%	27.88	370.63	
25			2010	0.3546	9.70%	3.44%	28.55	395.23	
26			GROWTH 2006 - 2010			5.45%	10.50%		3.22%
27			2011	0.3382	9.00%	3.04%		405.00	2.47%
28			2012	0.4873	11.00%	5.36%		420.00	3.09%
29			2014-16	0.4824	11.50%	5.55%	5.50%	425.00	1.46%
30									
31	POR	PORTLAND GENERAL ELECTRIC COMPANY	2006	0.4035	5.80%	2.34%	19.58	62.50	
32			2007	0.6009	11.00%	6.61%	21.05	62.53	
33			2008	0.3022	6.40%	1.93%	21.64	62.58	
34			2009	0.2290	6.20%	1.42%	20.50	75.21	
35			2010	0.3735	7.90%	2.95%	21.14	75.32	
36			GROWTH 2006 - 2010			3.05%	2.00%		4.77%
37			2011	0.4700	9.00%	4.23%		75.50	0.24%
38			2012	0.4732	9.00%	4.26%		75.75	0.29%
39			2014-16	0.4667	9.00%	4.20%	3.50%	76.50	0.31%

REFERENCES:

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ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	LOCAL DISTRIBUTION COMPANY NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PPL	PPL CORPORATION	2006	0.5197		17.30%		8.99%	13.30	385.04	
2			2007	0.5361		18.20%		9.76%	14.88	373.27	
3			2008	0.4531		18.20%		8.25%	13.55	374.58	
4			2009	-0.1597		8.10%		NMF	14.57	377.18	
5			2010	0.3886		12.00%		4.66%	16.98	483.39	
6			GROWTH 2006 - 2010					7.91%	7.00%		5.85%
7			2011	0.4167		12.00%		5.00%		578.00	19.57%
8			2012	0.4510		12.50%		5.64%		580.00	9.54%
9			2014-16	0.4333		11.50%		4.98%	9.00%	680.00	7.06%
10											
11	TE	TECO ENERGY, INC.	2006	0.3504		14.10%		4.94%	8.25	209.50	
12			2007	0.3858		13.20%		5.09%	9.56	210.90	
13			2008	-0.0390		8.10%		NMF	9.43	212.90	
14			2009	0.2000		10.30%		2.06%	9.75	213.90	
15			2010	0.2743		11.20%		3.07%	10.10	214.90	
16			GROWTH 2006 - 2010					3.79%	5.00%		0.64%
17			2011	0.3462		12.50%		4.33%		216.00	0.51%
18			2012	0.3862		13.50%		5.21%		217.00	0.49%
19			2014-16	0.4000		13.00%		5.20%	5.00%	220.00	0.47%
20											
21	WR	WESTAR ENERGY, INC.	2006	0.4787		10.70%		5.12%	17.62	87.39	
22			2007	0.4130		9.20%		3.80%	19.14	95.46	
23			2008	0.1145		6.20%		0.71%	20.18	108.31	
24			2009	0.0625		6.30%		0.39%	20.59	109.07	
25			2010	0.3111		8.20%		2.55%	21.25	112.13	
26			GROWTH 2006 - 2010					2.51%	6.00%		6.43%
27			2011	0.2381		7.50%		1.79%		117.00	4.34%
28			2012	0.3053		8.50%		2.59%		120.00	3.45%
29			2014-16	0.4000		10.00%		4.00%	2.00%	128.00	2.68%
30											
31	WEC	WISCONSIN ENERGY CORPORATION	2006	0.6515		10.80%		7.04%	12.35	233.94	
32			2007	0.6479		10.90%		7.06%	13.25	233.89	
33			2008	0.6447		10.70%		6.90%	14.27	233.84	
34			2009	0.5750		10.60%		6.10%	15.26	233.82	
35			2010	0.5833		12.00%		7.00%	16.26	233.77	
36			GROWTH 2006 - 2010					6.82%	7.50%		-0.02%
37			2011	0.5163		13.00%		6.71%		232.00	-0.76%
38			2012	0.4933		13.00%		6.41%		228.00	-1.24%
39			2014-16	0.4000		14.00%		5.60%	4.50%	224.00	-0.85%

REFERENCES:
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COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2010

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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
GROWTH RATE COMPARISON

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 6

LINE	STOCK		(A)	(B) ZACKS	(C) VALUE LINE PROJECTED			(D) VALUE LINE HISTORIC			(E) VALUE LINE &	(F) 5 - YEAR COMPOUND HISTORY		
NO.	SYMBOL	COMPANY NAME	(br) + (sv)	EPS	EPS	DPS	BVPS	EPS	DPS	BVPS	ZACKS AVGS.	EPS	DPS	BVPS
1	AEE	AMEREN CORP.	5.75%	2.55%	-2.00%	-3.00%	1.50%	-1.50%	-6.00%	2.50%	-0.85%	1.02%	-11.76%	0.23%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	4.72%	3.12%	4.50%	4.00%	4.50%	2.00%	2.00%	5.00%	3.59%	-2.35%	3.33%	4.53%
3	CNP	CENTERPOINT ENERGY, INC.	4.15%	1.13%	3.00%	3.00%	10.00%	5.00%	13.50%	8.50%	6.30%	-5.29%	6.78%	11.00%
4	CNL	CLECO CORPORATION	5.04%	2.37%	6.00%	9.50%	6.50%	7.50%	0.50%	11.00%	6.20%	13.91%	2.15%	9.35%
5	CMS	CMS ENERGY CORPORATION	5.30%	1.45%	7.00%	14.00%	5.00%	17.50%	-	1.50%	7.74%	20.07%	-	2.77%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	6.34%	2.98%	18.00%	-4.00%	6.50%	-16.00%	1.50%	4.50%	1.93%	-19.11%	-10.71%	11.31%
7	DTE	DTE ENERGY COMPANY	3.25%	3.60%	4.50%	4.00%	3.50%	2.50%	1.00%	3.50%	3.23%	11.15%	1.18%	4.69%
8	EIX	EDISON INTERNATIONAL	4.50%	2.93%	0.58%	0.54%	0.55%	1.46%	1.05%	1.05%	1.17%	0.53%	3.66%	8.21%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	12.61%	1.26%	6.00%	-	2.00%	-11.50%	-8.00%	7.00%	-0.54%	-1.42%	-15.91%	6.22%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	3.56%	1.40%	11.00%	1.00%	2.50%	-6.00%	-	1.00%	1.82%	-2.34%	0.00%	3.91%
11	IDA	IDACORP, INC.	5.35%	3.40%	4.00%	4.00%	5.00%	11.00%	-2.50%	4.50%	4.20%	5.85%	0.00%	4.74%
12	TEG	INTEGRYS ENERGY GROUP, INC.	3.12%	3.37%	9.00%	-	1.50%	-8.00%	4.00%	5.50%	2.56%	-1.98%	4.51%	1.35%
13	ITC	ITC HOLDINGS CORP.	12.34%	3.30%	14.00%	5.50%	10.50%	-	-	-	8.33%	32.55%	4.95%	15.10%
14	POM	PEPCO HOLDINGS INC.	2.10%	1.24%	2.50%	1.00%	2.00%	-5.00%	1.50%	1.00%	0.61%	-1.74%	0.95%	-0.04%
15	PCG	PG&E CORPORATION	5.82%	3.52%	6.00%	4.50%	5.50%	7.00%	-	10.50%	6.17%	0.54%	8.36%	6.21%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	4.21%	2.01%	7.50%	3.00%	3.50%	7.50%	-	2.00%	4.25%	9.85%	11.21%	1.93%
17	PPL	PPL CORPORATION	7.98%	2.61%	7.00%	3.50%	9.00%	1.00%	10.00%	7.00%	5.73%	0.00%	6.21%	6.30%
18	TE	TECO ENERGY, INC.	5.27%	1.31%	10.50%	4.50%	5.00%	12.00%	-0.50%	5.00%	5.40%	-0.87%	1.92%	5.19%
19	WR	WESTAR ENERGY, INC.	4.16%	1.77%	8.50%	3.00%	2.00%	1.00%	7.00%	6.00%	4.18%	-1.08%	6.06%	4.79%
20	WEC	WISCONSIN ENERGY CORPORATION	6.25%	2.15%	8.50%	16.00%	4.50%	8.50%	10.00%	7.50%	8.16%	9.82%	14.84%	7.12%
21					6.80%	4.11%	4.55%	1.89%	2.34%	4.98%		3.46%	1.99%	5.75%
22	AVERAGES		5.59%	2.37%		5.16%			3.07%		4.01%		3.73%	

REFERENCES:

COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THROUGH 20
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 08/26/2011, 09/23/2011 AND 11/04/2011

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AEE	AMEREN CORP.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)]	=	4.12%
3	CNP	CENTERPOINT ENERGY, INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
4	CNL	CLECO CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)]	=	3.89%
5	CMS	CMS ENERGY CORPORATION	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)]	=	4.34%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
7	DTE	DTE ENERGY COMPANY	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)]	=	4.34%
8	EIX	EDISON INTERNATIONAL	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)]	=	4.34%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)]	=	4.12%
11	IDA	IDACORP, INC.	k	=	0.97%	+ [	0.70	x (	9.90%	-	5.40%	)]	=	4.12%
12	TEG	INTEGRYS ENERGY GROUP, INC.	k	=	0.97%	+ [	0.90	x (	9.90%	-	5.40%	)]	=	5.02%
13	ITC	ITC HOLDINGS CORP.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
14	POM	PEPCO HOLDINGS INC.	k	=	0.97%	+ [	0.80	x (	9.90%	-	5.40%	)]	=	4.57%
15	PCG	PG&E CORPORATION	k	=	0.97%	+ [	0.55	x (	9.90%	-	5.40%	)]	=	3.44%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)]	=	4.34%
17	PPL	PPL CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)]	=	3.89%
18	TE	TECO ENERGY, INC.	k	=	0.97%	+ [	0.85	x (	9.90%	-	5.40%	)]	=	4.79%
19	WR	WESTAR ENERGY, INC.	k	=	0.97%	+ [	0.75	x (	9.90%	-	5.40%	)]	=	4.34%
20	WEC	WISCONSIN ENERGY CORPORATION	k	=	0.97%	+ [	0.65	x (	9.90%	-	5.40%	)]	=	3.89%
21	AVERAGE						0.75							4.32%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 09/23/2011 THROUGH 11/11/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOOK.

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	(A) r_f	+ [	$ß$	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AEE	AMEREN CORP.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
2	AEP	AMERICAN ELECTRIC POWER COMPANY, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
3	CNP	CENTERPOINT ENERGY, INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
4	CNL	CLECO CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
5	CMS	CMS ENERGY CORPORATION	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
6	CEG	CONSTELLATION ENERGY GROUP, INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
7	DTE	DTE ENERGY COMPANY	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
8	EIX	EDISON INTERNATIONAL	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
9	GXP	GREAT PLAINS ENERGY INCORPORATED	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
10	HE	HAWAIIAN ELECTRIC INDUSTRIES, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
11	IDA	IDACORP, INC.	k	=	0.97%	+ [	0.70	x (	11.90%	-	5.50%	)]	=	5.45%
12	TEG	INTEGRYS ENERGY GROUP, INC.	k	=	0.97%	+ [	0.90	x (	11.90%	-	5.50%	)]	=	6.73%
13	ITC	ITC HOLDINGS CORP.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
14	POM	PEPCO HOLDINGS INC.	k	=	0.97%	+ [	0.80	x (	11.90%	-	5.50%	)]	=	6.09%
15	PCG	PG&E CORPORATION	k	=	0.97%	+ [	0.55	x (	11.90%	-	5.50%	)]	=	4.49%
16	POR	PORTLAND GENERAL ELECTRIC COMPANY	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
17	PPL	PPL CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
18	TE	TECO ENERGY, INC.	k	=	0.97%	+ [	0.85	x (	11.90%	-	5.50%	)]	=	6.41%
19	WR	WESTAR ENERGY, INC.	k	=	0.97%	+ [	0.75	x (	11.90%	-	5.50%	)]	=	5.77%
20	WEC	WISCONSIN ENERGY CORPORATION	k	=	0.97%	+ [	0.65	x (	11.90%	-	5.50%	)]	=	5.13%
21	**AVERAGE**						0.75							5.74%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\, ß\, (r_m - r_f)\,]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
$ß$ = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)
r_f = PROXY FOR THE RISK FREE RATE ON INTERMEDIATE TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 09/23/2011 THROUGH 11/11/2011 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2010 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2011 YEARBOOK.

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 8

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.39%	1.90%	10.01%	6.98%	8.10%	7.50%	7.49%	9.86%	10.06%
2	1991	4.25%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.03%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.96%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.61%	4.00%	7.14%	3.60%	4.21%	4.25%	4.25%	8.31%	8.63%
6	1995	2.81%	2.50%	8.83%	5.21%	5.83%	5.49%	5.49%	7.89%	8.29%
7	1996	2.93%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	2.34%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.55%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.19%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.38%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	2.83%	0.80%	6.92%	3.41%	3.88%	3.40%	5.95%	7.59%	8.02%
13	2002	1.59%	1.60%	4.67%	1.17%	1.67%	1.61%	5.38%	7.41%	7.98%
14	2003	2.27%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.68%	3.60%	4.34%	2.34%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.39%	2.90%	6.16%	4.19%	3.22%	3.15%	4.57%	5.38%	5.78%
17	2006	3.24%	2.80%	7.97%	5.96%	4.97%	4.73%	4.91%	5.94%	6.30%
18	2007	2.85%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	CURRENT	3.90%	2.50%	3.25%	0.75%	0.00% - 0.25%	0.01%	3.22%	4.12%	4.76%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/11/2011
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/11/2011
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

ARIZONA PUBLIC SERVICE COMPANY
TEST YEAR ENDED DECEMBER 31, 2010
CAPITAL STRUCTURES OF SAMPLE COMPANIES (000's)

DOCKET NO. E-01345A-11-0224
SCHEDULE WAR - 9

LINE NO.		AEE	PCT.	AEP	PCT.	CNP	PCT.	CNL	PCT.	CMS	PCT.
1	DEBT	$ 3,949.0	48.7%	$ 15,502.0	53.2%	$ 9,119.0	77.6%	$ 1,399.7	51.5%	$ 6,448.0	69.4%
3	PREFERRED STOCK	80.0	1.0%	0.0	0.0%	0.0	0.0%	1.0	0.0%	0.0	0.0%
5	COMMON EQUITY	4,073.0	50.3%	13,622.0	46.8%	2,639.0	22.4%	1,317.2	48.5%	2,837.0	30.6%
7	TOTALS	$ 8,102.0	100%	$ 29,124.0	100%	$ 11,758.0	100%	$ 2,717.9	100%	$ 9,285.0	100%

LINE NO.		CEG	PCT.	DTE	PCT.	EIX	PCT.	GXP	PCT.	HE	PCT.
12	DEBT	$ 4,054.2	33.3%	$ 4,046.0	50.2%	$ 12,371.0	51.8%	$ 2,942.7	50.5%	$ 1,364.9	47.3%
14	PREFERRED STOCK	190.0	1.6%	0.0	0.0%	907.0	3.8%	0.0	0.0%	34.3	1.2%
16	COMMON EQUITY	7,918.0	65.1%	4,009.0	49.8%	10,583.0	44.4%	2,885.9	49.5%	1,483.6	51.5%
18	TOTALS	$ 12,162.2	100%	$ 8,055.0	100%	$ 23,861.0	100%	$ 5,828.6	100%	$ 2,882.9	100%

LINE NO.		IDA	PCT.	TEG	PCT.	ITC	PCT.	POM	PCT.	PCG	PCT.
23	DEBT	$ 1,488.3	49.2%	$ 2,161.6	42.2%	$ 2,496.9	69.1%	$ 3,629.0	46.2%	$ 10,906.0	49.2%
25	PREFERRED STOCK	0.0	0.0%	51.1	1.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
27	COMMON EQUITY	1,536.0	50.8%	2,905.8	56.8%	1,117.4	30.9%	4,230.0	53.8%	11,282.0	50.8%
29	TOTALS	$ 3,024.3	100%	$ 5,118.5	100%	$ 3,614.3	100%	$ 7,859.0	100%	$ 22,188.0	100%

LINE NO.		POR	PCT.	PPL	PCT.	TE	PCT.	WR	PCT.	WEC	PCT.
34	DEBT	$ 1,798.0	52.9%	$ 12,161.0	58.9%	$ 4,271.7	66.3%	$ 2,490.9	50.8%	$ 3,932.0	50.6%
36	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	30.4	0.4%
38	COMMON EQUITY	1,599.0	47.1%	8,478.0	41.1%	2,170.6	33.7%	2,410.4	49.2%	3,802.1	49.0%
40	TOTALS	$ 3,397.0	100%	$ 20,639.0	100%	$ 6,442.3	100%	$ 4,901.2	100%	$ 7,764.5	100%

LINE NO.		ELECTRIC COMPANY SAMPLE AVERAGE	PCT.
45	DEBT	$ 106,531.9	53.6%
47	PREFERRED STOCK	1,294	0.7%
49	COMMON EQUITY	90,899	45.7%
51	TOTALS	$ 198,724.7	100%

REFERENCE:
MOST RECENT SEC 10(k) FILINGS OR COMPANY ANNUAL REPORTS

EXHIBIT
RUCO
6
ADMITTED

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-11-0224

TESTIMONY IN SUPPORT OF SETTLEMENT AGREEMENT

OF

JODI A. JERICH

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JANUARY 18, 2012

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, occupation and business address for the record.

A. My name is Jodi Jerich. I am the Director of the Arizona Residential Utility Consumer Office (RUCO). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. My educational background and qualifications are set forth in Exhibit A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain RUCO's support of the Settlement Agreement.

Q. Did you represent RUCO during the previous APS rate case negotiations and ultimately provide testimony in support of that Settlement Agreement which resulted in Decision No. 71448?

A. Yes.

Q. Have you in your role as RUCO Director, participated in other settlement negotiations?

A. Yes. As Director, I have participated in settlement negotiations in other matters that have come before the Corporation Commission.[1] The majority of these negotiations have resulted in RUCO reaching an accord with the utility and the other settling parties and signing a settlement agreement. On the other hand, I have walked away from settlement talks when negotiations produced a result that RUCO found was not in the best interest of residential ratepayers. RUCO does not enter into settlements lightly. RUCO will not agree to settle simply as a means of avoiding litigation. However, in this matter, negotiations did produce reasonable and fair terms that RUCO can and does support.

THE SETTLEMENT PROCESS

Q. Was the negotiation process that resulted in the Settlement Agreement a proper and fair process?

A. Yes. The Settlement Agreement is the result of numerous hours of negotiation and a willingness among the parties to compromise. The

[1] 2008 APS Rate Case, Docket No. E-01345A-08-0172 (Decision No. 71448); 2010 Qwest/ CenturyLink Merger, Docket No. T-04190A-10-0194 (Decision No. 72232), 2010 SW Gas Rate Case, Docket No. G-01551A-10-0458 (Decision No. 72723). Goodman Water Rate Case, Docket No. W-02500A-10-0382 (pending), Arizona-American rate case, Docket No. A-01303A-10-0448 (pending).

negotiations were conducted in a fair and reasonable way that allowed each party the opportunity to participate. All intervenors had an opportunity to participate in every step of the negotiation. Notice for each scheduled meeting was sent to all parties electronically. Persons were able to participate via teleconference if necessary. Furthermore, APS created a secure website that allowed all parties to view all documents submitted as part of settlement negotiations. All parties were allowed to express their positions fully.

On December 9, 2013, Staff filed a Notice of Status and Preliminary Term Sheet which reflected the terms of the negotiations up to that date. The Commission held a Special Open Meeting on December 16, 2011 to review the Preliminary Term Sheet and have the opportunity to ask questions of any of the intervenors. RUCO, along with the other parties, attended the Special Open Meeting and answered questions posed by the Commissioners.

By RUCO's count, 22 parties signed the Settlement Agreement. These signatories represent a wide range of interests from agricultural interests, governmental entities, business and retail interests, industrial interests, low income advocates, union representatives, Commission Staff, AARP and RUCO.

Q. Did all the parties sign the proposed Settlement Agreement?

A. No. At the very end, a handful of parties choose not to sign the Agreement. These parties have the opportunity to file testimony to explain their reasons why they ultimately did not sign the Settlement Agreement.

Q. Why is a negotiated settlement process an appropriate way to resolve this matter?

A. By its very nature, a settlement finds middle ground that the parties can support. All the parties that participated in the settlement talks were sophisticated parties well seasoned in the Commission's regulatory processes and veterans of the negotiating table. All parties except Ms. Cynthia Zwick were represented by counsel. The fact that so many parties representing such varied interests were able to come together to reach consensus illustrates the balance, moderation and compromise of the document.

Settlement negotiations began only after each party had the opportunity to analyze the Company's Application, file its Direct Testimony and read the Direct Testimony of other Intervenors. Of course, the Settlement Agreement in no way eliminates the Commission's constitutional right and duty to review this matter and to make its own determination whether the Settlement is truly balanced and the rates are just and reasonable.

EXECUTIVE SUMMARY

Q. Please summarize your testimony.

A. The Settlement Agreement reflects an outcome that is fair to both the consumer and the Company and is in the public interest. Furthermore, this is a comprehensive Settlement Agreement. Its terms settle a wide range of issues that were of significant interest to several of the Intervenors.

RUCO supports this Agreement in its entirety because it contains numerous benefits to the consumer including an overall zero dollar base rate increase (and even a modest overall bill decrease in 2012) while keeping the Company on a path of financial health as set forth in the previous Settlement Agreement. Most notably, this proposed Settlement Agreement resolves the contentious and hotly debated issue of "decoupling". The proposed Settlement Agreement provides the Company with the "Lost Fixed Cost Recovery" ("LFCR") mechanism plus a viable "opt out" rate for residential customers who do not wish to be subject to the LFCR. The LFCR allows APS to recover lost revenues that are solely and directly attributable to lost sales due to Commission-approved energy efficiency programs. The opt out rate allows residential customers to choose an alternative base rate and not be subject to the annually increasing LFCR. This rate design flexibility is in the public interest for several reasons which will be set forth in greater detail below.

THIS SETTLEMENT AGREEMENT BUILDS ON THE PREVIOUS AGREEMENT WHILE ADDRESSING NEW CHALLENGES

Q. What were RUCO's priorities during the last rate case (Docket No. E-01345A-08-0172)?

A. As I stated in my testimony in support of the 2009 APS Settlement Agreement:

> "RUCO is deeply concerned with APS's *continuous marginal* credit rating and constant claims that a downgrade to "junk bond" status is imminent...The Settlement Agreement is a comprehensive strategy that provides a guiding hand for the utility to improve its financial condition in both the short and long term...The Settlement Agreement helps to align the interests of stockholders and ratepayers, and it sets forth a reasonable and rational strategy that is likely to improve APS's financial metrics and, in the long run, stem the constant flow of rate increases that would be likely to occur if the Commission were simply to continue to increase rates incrementally without addressing the root of the Company's weak financial position." (Jerich Testimony in Support of the Settlement Agreement, July 1, 2009, pp. 9, 11)

Q. Does RUCO believe the 2009 Settlement Agreement has had a positive effect?

A. Absolutely. APS's credit rating has been upgraded to BBB with a positive outlook from BBB-. RUCO believes this is due in large part to APS's compliance with the terms of the 2009 Settlement Agreement such as (1) issuing the first tranche of $250 million equity infusion out of the total commitment of $700 million equity infusion by December 31, 2014 (Section 8.1), (2) achieving a Test Year 54% adjusted debt/adjusted total capitalization ratio by "striving to reduce total debt from 57% to 52%" (Section 8.3) ,and (3) reducing expenses to total $150 million at the end of five years. (Section 7.1).

Mr. Hatfield's direct testimony on behalf of APS discusses APS's improved financial condition since the last rate case and its compliance with the terms of the 2009 Settlement Agreement.

Q. Must APS continue to comply with the terms of the previous Settlement Agreement as ordered by Decision No. 71448?

A. Yes. Decision No. 71448 approved the terms of the 2009 Settlement Agreement which established the five year "Plan Term" which ends December 31, 2014. The Settlement Agreement in this rate case must be read in harmony with the provisions of the 2009 Settlement Agreement.

Q. Do you believe the terms of this Settlement Agreement are consistent with the priorities articulated by RUCO in the previous rate case?

A. Yes. RUCO finds that this Settlement Agreement has several components that benefit the utility and allow it to maintain its creditworthiness. In summary, these include a 10.0% authorized ROE, the Lost Fixed Cost Recovery mechanism, the inclusion of Four Corners in rate base should the Commission approve and APS acquire Southern California Edison's interest and the creation of the Environmental Improvement Surcharge. The Settlement eliminates the current EIS that collects ratepayer money to pay for environmental improvements up front and is treated as CIAC.[2] The new EIS reimburses APS for shareholder funds used for environmental improvements and is treated as revenues.

SETTLEMENT PROVISIONS

Q. In summary, what are the benefits to the residential consumer?

A. The benefits to the residential consumer are:

- A zero dollar base rate increase. (1.5)
- A zero dollar bill impact (or slight decrease) for the remainder of 2012. (1.5)
- APS agrees not to raise base rates prior to July 1, 2016. (1.5)
- A lower base rate of fuel to recognize lower fuel costs. (7.1)
- The probability of a lower PSA costs if APS's acquisition of SCE's interest in Four Corners is approved and APS makes off-system sales of electricity generated from Units 1-3 prior to their closure. (10.2)

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[2] See Decision No. 69663 (Docket No. E-01345A-05-0816

- The application of interest on overcollections of the PSA (in lieu of the 90/10 sharing provision). (7.3)
- Periodic audits of APS's fuel procurement practices. (7.4)
- Establishment of a limited mechanism (the "LFCR") to recover lost revenues directly and solely attributable to the Company's energy efficiency and distributed generation goals as mandated by the Commission. (Section IX)
- Capping the amount the LFCR may collect from residential ratepayers to 1% year over year of total company revenues. (9.4)
- Ability to opt out of paying the annually increasing LFCR by selecting a fixed rate in lieu of the LFCR that is approximately 1% - 2% higher than the current base rate. (9.2, 9.8)
- Allowing customers to change from the LFCR to the opt out rate (within certain parameters) to understand which alternative works better for them. (9.12)
- A Company sponsored education and outreach program to inform customers about the LFCR and their chose between the LFCR and the opt out rate. (9.9)
- Withdrawal of APS's request to recover the cost of chemicals through the PSA. (7.2)
- Deferral of a portion of any property tax rate increases with no interest applied to the deferrals, but full recognition of any property tax rate decrease. (12.1)

- $5 million of shareholder funds to augment APS's bill assistance program.
- Stakeholder meetings subsequent to the rate case to develop recommendations to the Commission on how to make the APS bill easier to understand. (Section XVI)

Q. In summary, what are the benefits to the Company?

A. The benefits to the Company are:

- A 10.0% authorized ROE.
- Creation of the LFCR to allow the Company to recover lost revenues associated with EE and DG programs. (9.2, 9.3)
- 15 months of post test year plant in rate base. (3.1)
- The establishment of the Environmental Improvement Surcharge adjuster. (Section XI)
- Elimination of the 90/10 sharing provision of the PSA. (7.3)
- Application of interest to any undercollection of the PSA. (7.3)
- Rate base treatment of the acquisition of SCE's interests in Units 4 & 5 at Four Corners should the Commission approve their purchase and find the costs prudent. (Section X)

PUBLIC INTEREST

Q. How is the public interest satisfied by the Settlement Agreement?

A. At the most fundamental level, the settlement satisfies the public interest from RUCO's perspective in that it provides a framework that provides for a zero dollar base rate increase, a zero dollar overall bill impact in 2012 while allowing the Company to maintain its financial health through enumerated benefits including the LFCR and inclusion of Four Corners in rate base.

The Settlement Agreement also satisfies the public interest by providing a fair and balanced approach to addressing the Company's lost revenue. RUCO believes that providing the Company a narrowly tailored mechanism to recover lost revenue directly and solely associated with Commission-mandated EE and DG programs while providing the ratepayer the ability to opt out of the LFCR with a slightly higher base rate is a reasonable solution to what is undoubtedly the most contentious issue in this case. The Company can meet whatever energy efficiency requirements the Commission sets through the LFCR without shifting the risks of the economy, weather and other factors on to the ratepayer.

RATE IMPACT

Q. What was RUCO's position in its direct case?

A. In its Direct Testimony, RUCO recommended a 10.0% ROE and a zero dollar base rate increase. These positions have been incorporated into the Settlement Agreement.

Q. Does a zero base rate increase until 2016 translate into a zero overall bill impact for that same period?

A. No it does not. The existing APS rate design includes several adjusters that adjust annually outside of any rate case. These adjusters, such as the Power Supply Adjuster (PSA), the Transmission Cost Adjuster (TCA), the Renewable Energy Surcharge (RES) and the Demand Side Management Adjuster Mechanism (DSMAC) will all adjust at their regularly scheduled times through 2016. The Settlement Agreement was able to achieve a zero base rate impact and a slight decrease in the overall bill because of the lower cost of fuel and the overcollected balance in the PSA. The Settlement Agreement reduces the base rate of fuel. It also defers resetting the PSA until February 2013 instead of resetting it concurrently with the implementation of new rates as in the previous rate case. It is this delay in the resetting of the overcollected balance of the PSA that allows the customers to continue to receive a PSA credit through February 2013. At that time, the PSA will be reset as it does every year.

Q. Are there other provisions in the Settlement Agreement that may affect the ratepayer's bill outside of the setting of the base rate?

A. Yes. Section X of the Settlement Agreement provides for the possible inclusion of the SCE interests in Units 4 and 5 at Four Corner if the Commission approves APS's request to purchase this interest and the Commission finds the transaction prudent. If that happens, the Company will seek to include the costs as set forth in Section 10.2 in ratebase and recover those costs through a Four Corners rate rider adjustment. Such adjustment may not occur prior to July 1, 2013. The inclusion of APS's additional interest in Units 4 and 5 in ratebase will increase the bill by approximately $2.08 per month for the average E-12 residential customer. However, the additional increase in the bill for putting the Four Corners plant into ratebase will likely be offset to some degree by any off system sales APS makes from Units 1-3 until those units close. These sales will affect the PSA calculation.

Q. How does the new EIS adjuster impact the customer's bill?

A. There will be no change. The rate set for the new EIS adjuster is the same rate that is currently in place for the existing EIS.

Q. How can the Commission better understand how the overall bill will change if the Commission approves the Settlement Agreement?

A. APS docketed a letter on January 9, 2012 explaining the bill impacts associated with the Settlement Agreement. Attached to that letter are the bill impact statements for various customer classes through 2013.

RUCO'S ACCEPTANCE OF THE LFCR

Q. In light of RUCO's past opposition to full revenue decoupling and even the limited decoupling proposal in the Southwest Gas Settlement Agreement, why would RUCO support the LFCR in this Settlement Agreement?

A. RUCO has consistently stated that a decoupling mechanism is more appropriate for an electric generation utility than a natural gas distribution utility because energy efficiency programs have the ability to delay the need to build more and very expensive plant including new electric generating facilities and transmission lines.

RUCO supports the LFCR in this rate case because the LFCR (1) allows recovery only for lost revenues directly and solely associated with APS's Commission-mandated energy efficiency and distributed generation programs, (2) cannot exceed **<u>1%</u>** year over year of total company revenues, and (3) includes a viable "opt out" rate for customers who elect not to be subject to the LFCR adjuster. The LFCR is narrowly tailored to capture only those lost revenues connected to EE and DG programs. The Company has stated on the record that it does not need full revenue decoupling in order to remain financially viable and meet its energy efficiency obligations. *"Lost Fixed Cost Recovery can accommodate whatever energy efficiency you authorize in the process. It may not be the most robust, but it's a workable mechanism that we can live with."*[3]

The LFCR is different than the two decoupling alternatives proposed in the Southwest Gas Settlement Agreement. RUCO did not support that settlement agreement because it found neither decoupling options in the best interest of ratepayers. Unlike full revenue decoupling, the LFCR does not allow recovery for lost revenues connected to factors such as home foreclosures, businesses closing their doors, the poor economy, weather or other factors. And unlike the second decoupling proposal in the Southwest Gas case, this LFCR does not shift the risk of lost revenue due to the weather on to the ratepayer. Neither decoupling option was as narrowly tailored as the LFCR in this Settlement Agreement. Neither decoupling mechanism included an opt out rate.

[3] Jeff Guldner, APS, Special Open Meeting to discuss APS settlement, 12/16,2011, p. 78.

Q. Why has RUCO opposed decoupling mechanisms in the past?

A. In previous rate cases, RUCO has opposed decoupling for several reasons. First, RUCO has argued loudly that a decoupling mechanism that constantly changes the customer's rates does not provide the correct price signal to encourage conservation. RUCO has consistently voiced the proposition that making a customer share a portion of their savings due to their own efforts to reduce their bill is unfair and can even discourage conservation. Second, RUCO has pointed out that while all residential customers would be subject to the decoupling mechanism, not all customers could participate, or participate fully, in DSM, EE and DG programs. These customers include low usage customers, renters, seniors, customers with limited incomes, and those customers who have already implemented as many programs as practical to reduce consumption. Finally, RUCO believes it is fundamentally unfair to have customers cover the utility's lost revenues due to a poor economy, lost sales due to home foreclosures, businesses that have closed their doors, and extreme weather conditions. Such a mechanism inappropriately shifts the risk of these factors away from the regulated utility that has an opportunity to earn an authorized rate of return to the captive customer.

In light of Commission-mandated policies that require the utility to sell less energy going forward while setting their rates on a historical test year, RUCO has offered other alternatives to address the utility's revenue erosion. These alternatives have included placing more of the fixed costs into the base rates and providing an ROE premium.

Q. What is the Opt Out Rate?

A. The opt out rate is an optional basic service charge, graduated by KWh monthly usage. It recovers only a small portion of fixed costs through an incremental increase in the basic service charge. It does not recover all fixed costs and is not a straight fixed variable rate design.

Q. Was the opt out rate a critical component in RUCO's support of the Settlement Agreement?

A. Absolutely. Without the opt out rate, it is highly unlikely RUCO would have signed the Settlement Agreement.

Residential customers who elect the opt out rate will agree to an increase to the basic service charge and that rate will remain fixed for the entire term of the Settlement Agreement. Alternatively, a customer who selects the opt out rate chooses to be subject to an annually increasing LFCR adjuster. RUCO believes this opt out rate provides rate stability and a better price signal to encourage reduced consumption. As shown in Attachment E to the Settlement Agreement, the opt out rate is approximately a 1% to 2% increase in a customer's bill. To further benefit the ratepayer, residential customers on any rate schedule (i.e., Time of

Use or Non Time of Use schedules), can stay on their preferred rate schedule and still elect the opt out rate. The Company must perform customer outreach to educate the customers of the LFCR and the opt out rate. If a customer selects the opt out rate, the customer will not be charged the opt out rate until the customers who select the LFCR are charged. Finally, the LFCR Plan of Administration allows a residential customer who has selected one option over the other has to switch to the other option (within certain parameters) to provide maximum choice for the consumer.

Q. What are some other benefits to the opt out rate?

A. The opt out rate has several benefits. First, the Commission has witnessed the strong opposition to decoupling from ratepayers around the state. Literally thousands of Arizona residents have voiced their opposition to decoupling. The opt out rate provides customers with the ability to not be subject to the LFCR. Furthermore, the customer can elect to spend some time on both rates to see which one works better from their own experience. Second, by having the LFCR and the opt out rate, APS will be able to collect data on the number of customers participating in either rate. This information will be helpful to the Commission going forward as decoupling, in whatever form for whatever utility, is considered. Third, this opt out rate can help the utility and the Commission achieve good will among ratepayers.

POSSIBLE RATEBASE TREATMENT OF FOUR CORNERS

Q. Why does RUCO support inclusion of the acquisition of SCE's interests in Four Corners into rate base?

A. RUCO supported and continues to support APS's request to acquire SCE's interest in Four Corners. RUCO also supported a deferral order in that case. In RUCO's opinion, it makes sense to allow timely recovery for plant whose acquisition RUCO finds in the public interest and provides both a financial and environmental benefit to the ratepayer as well as a vitally needed economic driver for the Navajo Nation.

OTHER PROVISIONS

Q. Why does RUCO support applying the PSA and the DSMAC to low income ratepayers?

A. This provision was not part of RUCO's Direct Testimony. However, after reading Staff's testimony in support of applying these adjusters to these residential ratepayers and in the course of give and take in the negotiating process, RUCO supports the application of these adjusters to all residential ratepayers. Finally, RUCO notes that the application of these adjusters to low income customers was included in the Preliminary Term Sheet docketed December 9, 2011 which was the subject of a Special Open Meeting on December 16, 2011.

Q. Why does RUCO support a base rate freeze until 2016?

A. RUCO supported the 2009 Settlement Agreement that called for rates in this case to remain in effect until December 31, 2014. RUCO, in its Direct Testimony, did not consider extending this moratorium past the date agreed to under the previous settlement. However, after reading Staff's Direct Testimony and through the give and take of the negotiations, the Company accepted the extension of the base rate freeze and RUCO finds that that a stable base rate with the ability for the Company to remain financially healthy through changes in its adjusters in the public interest.

Q. Why does RUCO support the elimination of the 90/10 sharing provision to the PSA?

A. Again, RUCO supported the 2009 Settlement Agreement which retained the 90/10 sharing provision and in our direct testimony did not agree with the Company's request to eliminate it in this rate case. However, in the process of give and take RUCO has agreed to support its elimination in exchange for all the other ratepayer benefits that this Settlement Agreement provides. RUCO also points out that as a substitute for the 90/10 sharing provision, the Settlement Agreement assesses interest annually to the benefit of the ratepayer for any overcollection at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is greater. The Settlement Agreement also assesses interest annually in favor of the Company, for any undercollection at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less. RUCO finds this mechanism a suitable alternative to the 90/10 sharing provision.

Q. Does RUCO support making the APS bill easier for customers to understand?

A. Yes. RUCO has some specific ideas regarding the need to provide transparent information on the RES and DSM adjusters to the public. RUCO also has heard several complaints from customers over the confusion of the line item detail of the unbundled elements of the bill. RUCO will participate in the stakeholder work group as set forth in the Settlement Agreement.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT A

Statement of Qualifications

Jodi A. Jerich
Director
Arizona Residential Utility Consumer Office ("RUCO")

Governor Brewer appointed me to serve as the Director of RUCO in February 2009. The Arizona State Senate found my qualifications met the statutory requirements found in Arizona Revised Statutes §40-462 and confirmed my appointment. As Director, I oversee and approve all testimony and briefs filed by RUCO. In consultation with my staff, I direct the public policy decisions of the office.

From 2003 through 2005, I was employed at the Arizona Corporation Commission as the Policy Advisor to Corporation Commissioner Mike Gleason. In that role, I advised the Commissioner on matters coming before the Commission. I was actively involved in the utility policy-making decisions of that Commissioner's office.

Except for the time I was employed by the Commission, from 1997 through 2008, I was employed at the Arizona House of Representatives. I held several positions during my tenure, eventually becoming Chief of Staff and Counsel to the Majority Caucus. Relevant to the question at hand, I advised Legislators on matters involving water, energy, Commission jurisdiction and utility security.

In 2006, when Governor Janet Napolitano appointed Barry Wong to fill the Commission seat vacated by Commissioner Marc Spitzer's appointment to the Federal Energy Regulatory Commission (FERC), I took a leave of absence from the Legislature for a short time in order to assist Commissioner Wong in establishing his office.

I am a Phi Beta Kappa graduate of Indiana University. I also have a law degree from Indiana University and am a member of the Arizona and Tennessee bars.

In my position as RUCO Director, I have filed testimony detailing RUCO's position on numerous matters in several dockets. Most recently, I provided testimony on RUCO's position on decoupling in the pending UNS Gas, Inc. rate case. (Docket No. G-04204A-11-0158)

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTIES THROUGHOUT ARIZONA.

DOCKET NO. G-01551A-10-0458

EXHIBIT
RUCO
7
ADMITTED
PENGAD 800-631-6989

At: Phoenix, Arizona

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VOLUME II

(Pages 254 through 513, inclusive)

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INDEX TO EXAMINATIONS

RALPH CAVANAGH,

called as a witness on behalf of the Natural Resources Defense Council, having been first duly sworn by the Certified Reporter to speak the truth and nothing but the truth, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. SANCHEZ:

Q. If you would state your name and your address for the record.

A. My name is Ralph Cavanagh. And my address is 111 Sutter Street, San Francisco, California.

Q. So if you would settle a debate, just to be clear for the record, it is Cavanagh, not Cavanagh?

A. I answer to either, but just rhyme it with banana.

Q. Perfect.

And by whom are you employed?

A. The Natural Resources Defense Council, NRDC.

Q. And did you prefile testimony in this case?

A. Yes, both direct testimony and testimony on the settlement.

MS. SANCHEZ: I would like to go ahead and mark your direct testimony, that's the direct testimony of Ralph Cavanagh, as NRDC Exhibit 1, and the testimony of

Ralph Cavanagh in support of the settlement as NRDC Exhibit 2.

BY MS. SANCHEZ:

Q. And do you have a copy of both?

A. Yes.

Q. Do you have any changes or corrections to make to this testimony?

A. No.

Q. If I asked you the same questions today as are in the prefiled testimony, would your answers be the same?

A. Yes.

Q. And is this testimony true and correct, to the best of your knowledge and belief?

A. Yes.

Q. Very good.

Okay. Mr. Cavanagh, why is the settlement in the public interest?

A. I evaluated the settlement from the perspective first of someone who was grateful to be asked by the Commission to participate in its workshops last spring. I noted at the time that it was the first time I had been invited back to the Commission since my previous appearance 22 years earlier, and I encourage the Commission not to draw any firm conclusions from this rather extended interval.

I was extraordinarily impressed by those hearings as the most thorough going review of the issues surrounding disincentives to energy efficiency that I had seen in the decades I have been working on this issue in commissions across the country.

And I think that my value to the Commission in this proceeding likely lies simply in bringing that experience to bear on this proposal, and commenting from the perspective of that experience on the reasonableness of the proposal and its status in the public interest.

What I want the Commissioners to know is that in my view, the proposed settlement is in the public interest, is entirely consistent with the statement of principles you adopted at the end of December, and, perhaps most important, is a critical step toward the big prize here, which I regard as the literally billions of dollars of bill reductions potentially available if we can meet and exceed this Commission's energy efficiency targets for natural gas and electricity.

Q. Thank you.

And Mr. Cavanagh, within that settlement there is an Option A and Option B. And why is Option B better than Option A?

A. My view -- and to be clear, NRDC supports the settlement, but we have a very strong preference for Option B. Our view is, and my view, is that Option B is the full decoupling alternative preferred by the Commission in its policy statement, that Option A is a partial decoupling alternative built around a lost revenue recovery mechanism that was fully ventilated in the workshops.

And I agree with the Commission's policy statement that full decoupling is preferable. It is preferable because it is administratively similar, and because it decisively removes the conflicts of interest between the utility and energy efficiency progress for Arizona in a way that Option A simply does not. Both options deal responsibly, I think, with the weather risks and provide customer benefits there.

Q. Mr. Cavanagh, doesn't Alternative B end up paying Southwest Gas for energy savings they had nothing to do with?

A. No. I think -- my answer is, short answer is no. There is no question that much of the opposition and concern about this proposal comes from what I think is the mistaken belief that we are either paying Southwest Gas for things it hasn't done or we are still paying Southwest Gas for things that they ought to do anyway.

And the most important thing for me to emphasize is that revenue decoupling doesn't pay Southwest Gas anything extra to do anything. What it does is to remove an automatic penalty to Southwest Gas whenever it or its customers take steps in the direction of meeting the Commission's energy efficiency goals.

And I place removing an automatic penalty on a different footing from paying you extra or adding a cost element to customers' bills. The revenue decoupling proposal in Item B doesn't add any costs to any Arizonans' natural gas bill.

And many -- I have read on the Commission's website, what many of those customers said, Commissioner Newman. And if I believed that this was a ruinous cost increase at a time of statewide economic calamity, I would be up here screaming about it, too.

I think many of those commentators would feel differently if they knew that revenue decoupling doesn't add a nickel to anybody's bill. It is simply a way of ensuring that the recovery of costs already approved by the Commission won't be affected by unexpected changes in natural gas use. And I think that's a good thing. Alternative A does not provide that assurance, Alternative B does.

Q. All right. Mr. Cavanagh, are you familiar with the testimony filed by RUCO in this case?

A. Yes.

Q. RUCO has proposed as an alternative to revenue decoupling an increase in customer charges. Are you familiar with that proposal?

A. Yes.

Q. Do you believe that proposal is in utility customers' best interests?

A. I do not know, because for me the crucial unfortunate thing about that proposal is that by putting more of the customer's bill in a fixed charge and less in the variable charge, you are reducing every customer's reward for saving energy, at a time when this Commission is rightly pressing for more progress on energy efficiency.

I think the right course of action lies in continuing to reward customers for energy efficiency. At least the concern level and in the policy statement in removing disincentives the Commission was very clear that it wanted to see rate designs that were supportive of energy efficiency, not rate designs that constrained or reduced it.

Q. There was a question posed earlier to Mr. Hansen that I would like to follow up and present to you. Have you observed changes in utility support for efficiency standards as a result of decoupling?

A. I have. And this is, unlike Dr. Hansen, this is my day job. Work on energy efficiency standards has been a core part of what I have done at NRDC for more than 30 years. I know that this Commission understands the importance of having efficiency standards and efficiency incentives harmonized and integrated. And what I can tell you, based on a whole lot of years of watching this play out, is that it makes a world of difference in terms of progress on efficiency standards and effective implementation of standards.

It's equally important to have a supportive utility. Utilities that have had access to decoupling and other forms of incentives to promote energy efficiency have made a palpable difference, in my opinion, in progress at both the state and national level in advancing the cause not just in getting good standards in place, but making sure they are effectively implemented.

Q. Thank you.

Have you reviewed Dr. Johnson's testimony in particular filed in opposition to the settlement which was filed July 29th?

A. Yes.

Q. At page 6 of Dr. Johnson's testimony he described decoupling as, quote, embarking on risky, unchartered waters. Do you agree with that description?

A. I do not. And what I want to emphasize to the Commission is that in terms of the decoupling of natural gas utilities, the path is not only -- it is not an uncharted path; there are many buoys. The path has been trod for more than 30 years. There are now at least 22 states with experience in natural gas decoupling.

Commissioners may recall that during the workshops there was introduced to the Commission, and still on the record, the most authoritative assessment of all of those decoupling mechanisms undertaken before or since, which makes clear that in every critical relevant category, the settlement proposal before you with Option B is in the mainstream of natural gas utility experience with revenue decoupling.

It is not -- not only could it not fairly be characterized, I think, as risky or uncharted. It is, if anything, to be faulted for its vanilla and conservative character. But since that has many consumer protection features that were important to some of the settling parties, it does not affect our support for it.

I just resist with all the fiber of my being the notion that it is somehow experimental or dangerous.

And I will point out as far as I know there is nothing in the record to suggest that any of those other natural gas decoupling mechanisms, and there are dozens of mechanisms and there are dozens of rate adjustments under the mechanisms, now has produced anything that should give concern to this Commission in terms of unpleasant surprises.

MS. SANCHEZ: Thank you, Mr. Cavanagh.

I actually have no further questions, Your Honor, and I move the admission of NRDC Exhibit 1 and NRDC Exhibit 2, and I would tender this witness for cross-examination.

ACALJ NODES: All right. Thank you. Any objection to admission of those exhibits?

MR. GRANT: None.

ACALJ NODES: NRDC Exhibit 1 and 2 are admitted.

(Exhibit NRDC-1 and NRDC-2 were admitted into evidence.)

ACALJ NODES: Mr. Brown, questions?

MR. BROWN: Yes. Thanks, Judge.

CROSS-EXAMINATION

BY MR. BROWN:

Q. Good late morning, or afternoon I guess almost, Mr. Cavanagh. Justin Brown on behalf of Southwest Gas.

You mentioned your invitation to the Arizona Corporation Commission's workshops. I am wondering if you could provide a little more summary. And then you mentioned 30 years of doing, I guess, lobbying type work. Can you provide --

A. Analysis.

Q. Analysis, thank you. Can you provide kind of a brief summary of your experience studying and testifying regarding decoupling mechanisms?

A. The concept of decoupling on the natural gas side is now more than [illegible] years ago, but much of the activity has occurred over the last decade. And much of that is captured in the comprehensive assessment I mentioned which was authored by Pamela Lesch and referenced in my testimony.

I have been involved with the discussion, negotiation, advocacy around many of those negotiations over the past decades. It is one of the principal responsibilities I have, in addition to work on efficiency standards, as I mentioned a moment ago.

And although I guess I began my career assuming I would spend most of my time suing utilities, in fact what this work has persuaded me is that they are a critical part of the solution in terms of energy efficiency progress, particularly the aggressive type that this Commission rightly demands.

And I would say that my bottom line conclusion from all of this is that matters enormously whether commissions have acted to remove an inherent conflict of interest between their utilities and energy efficiency progress and that, where commissions are willing to do that, I agree with Dr. Hansen that the results are palpable and enduring.

Q. Based on your experience working with the concept of revenue decoupling, can you please explain why you believe this proposed change in or departure from traditional regulation that would be attributable to the mechanism under Alternative B is good for customers?

A. It is fundamentally good for customers because it removes a fundamental conflict of interest between the utility, viewed in terms of its shareholder interests, and the customers in terms of achievement of energy efficiency objectives, and in particular the Commission's objective to get all cost effective energy efficiency as quickly as possible. Getting those interests into alignment opens the door for what, by the Commission's reckoning in the policy statement from December of last year, are literally billions of dollars of savings over the next 20 years looking only on the electric side. I think Commissioner Newman mentioned, the number I believe is $9 billion in terms of net benefits on the electric side. And on the natural gas side, I agree with Jeff Schlegel's testimony that the down payment we can expect from just the first installment of programs that Southwest has promised to bring forward under its efficiency portfolio, just the first installment is in excess of $13 million net benefit.

Those are the most important reasons why I think that the interest of customers lies in approving the settlement and Alternative B.

Q. Again, you mentioned participation in the Commission's workshops on decoupling and financial disincentives. Could you respond to RUCO's suggestion in their testimony that we need more study of the decoupling in Arizona?

A. Again, Commissioners, I think the most important thing for me to say is I do not recall a more thorough evaluation of the alternatives, of the skeptical arguments, a more thorough financial analysis commissioned by one of the nation's top federal research laboratories, the engagement of the Regulatory Assistance Project, which is the gold standard for regulatory experience, and at a time when we had the record of 22 states with natural gas decoupling and 12 with electric decoupling to draw upon. If after all of that someone thinks we need more study, all I can say is I fear they will never be satisfied.

Q. Why should the Commission approve a full revenue decoupling mechanism, Mr. Cavanagh, as set forth in Alternative B, when it decouples revenues from sales for more than just the company's energy efficiency programs, for example, reductions due to warmer weather, the economy, or any other reasons other than the company sponsored programs?

A. Sure. And this is an important point that I tried to address in my testimony at some length.

First of all, on the weather point, I think the Commission did a thorough assessment of all the reasons why both the company and its customers are better off if there are prompt refunds for billing excesses associated with extreme weather. So I am hoping that one is behind us. That's a common feature of both Alternative A and B.

The big difference between A and B is A purports to say, well, we are only going to reward you for your programs, whereas B says we are going to completely decouple, we are going to remove any linkage between financial health and sales.

And this issue has come up repeatedly already today, but my judgment, again, looking across these multiple states and multiple contexts is that the lost revenue recovery mechanism, which is the heart of Option A, whatever its superficial appeal, quote, we are only paying them for things they actually did, is a nightmare in practice administratively. And it leads to what I called in my testimony perverse effects, leading my friends on the Staff to wonder what I could possibly have been thinking of.

The perverse incentive associated with lost revenue recovery is that the most profitable programs for Southwest Gas are those that look good on paper and don't save anything in practice or don't have enduring savings in practice. Because then, of course, you get to recover twice. You get paid for the illusory lost revenues, and then you recover them again when the sales occur that weren't actually eliminated.

That strikes me as unfortunate getting the incentives that badly out of whack. It also strikes me unfortunate that the Commission will have to spend so much of its time presiding over battles over how much a compact fluorescent light bulb in house Y actually saved and how long it lasted.

And finally, it strikes me as unfortunate that the Commission loses all of the opportunities for Southwest Gas outside the context of its specific programs to act to improve efficiency. And I thought the exchanges with Dr. Hansen, which I agreed with entirely, were very constructive on that point. There are a host of ways utilities can influence customer behavior, the evolution of efficiency standards, creatively market to customers that will never show up in the roster of, quote, savings from programs.

But you want to mobilize the hometown utility to do everything they can think of, and you do not want it having the view that only specific kinds of programs with specific kinds of very clearly identified results, that that's all that matters.

To get to the Commission's objectives to achieve all cost effective energy efficiency for Arizona we need an all out partnership involving the utility and its customers. We don't want it constrained in that way.

And finally, I resist with every ounce of my remaining energy the notion that we are paying the utility for doing anything with revenue decoupling. We are simply withholding automatic penalties when efficiencies improve, and that strikes me as a good public policy.

Q. I am not sure if you listened to the testimony on Wednesday, the first day of hearing, but Mr. Hester, the company's witness, testified in response to some questions that Southwest Gas has historically experienced a chronic declining consumption. And I think he gave the example that in 2004, the test year volumes were based on 347 therms per customer, and 2007 it was down to 332, and in this case it was at 298.

With that backdrop, if the Commission's decoupling policy statement was developed to address disincentives for energy efficiency related to the Commission's energy efficiency rules, requiring an additional 6 percent decline by 2020, as you mentioned earlier, then in light of Mr. Hester's testimony regarding the company's chronic decline in consumption, why should the Commission approve full revenue decoupling for a utility like Southwest Gas as opposed to a utility that has been experiencing perhaps increasing consumption per customer?

A. Well, because the Commission wants, I think, a fully engaged utility partner in this tremendously important joint effort to get natural gas savings that, remember, go well beyond current levels. We are not hitting these levels of achievement now.

I don't know of any gas utility in the country that is hitting targets as aggressive as the Commission has established, although that won't prevent me from trying to push everybody to do better. And I know how tough a sell it is going to be with management to say that in an atmosphere where you have already got -- in an environment where you already have declining use per customer, we want you to put your foot on the accelerator, we want you to get even further and more aggressive reductions, and of course you will keep bleeding fixed cost recovery as you do it.

That does not strike me -- and I am not here as an advocate for utility shareholders. I represent an environmental organization. But I know how badly we need that utility partnership. And that strikes me as a losing proposition in terms of engaging utility management for the full effort, the all out push that's going to be required to get success here.

Q. Do you agree with the testimony that RUCO put forth asserting that decoupling may have the effect of discouraging consumers from conserving?

A. No.

Q. And could you explain why?

A. I referred in my testimony to a specific point that the Oregon commission made in response to that argument. And I think what the Oregon commission correctly found -- and this was for Portland General in

Oregon -- was that any individual customer making a significant effort is going to be able to conserve, first of all, far more than any plausible decoupling adjustment would give back, and second, that any rational customer -- I think this was a point Dr. Hansen was trying to make -- will look at this and say wait a minute, I am still paying for natural gas based on how much I use, whether it nudges up or nudges down, the course of economic interest for me lies in minimizing my use.

I think much of the indignation from people who didn't like the decoupling proposal reflected a misunderstanding on this point. There was a very eloquent woman in particular who caught my eye who said what I hate about this is that what the company is saying to me, we want a certain amount of money, so regardless of usage, just hand over your paycheck. And if that's what we were talking about here, I can imagine why there is so much outrage.

But the key is that's the opposite of what we are doing. We are continuing to charge for natural gas based on how much you use. We are not introducing a system that bills you independently of usage. And for me that's a major part of the reason why the Commission should approve the settlement and Alternative B.

MR. BROWN: I have no further questions. Thank you, Mr. Cavanagh.

ACALJ NODES: Mr. Grant, any questions?

CROSS-EXAMINATION

BY MR. GRANT:

Q. Mr. Cavanagh, good afternoon. Mike Grant for AIC.

A. Yes.

Q. Just one, I think, because obviously in your discussions and also in your testimony -- and I know a little bit about your background -- you are exceptionally familiar with this area. So I want to ask you, I think, one of the last questions that I asked Dr. Hansen. And that is: Do you find that the consumer protections, the conditions of this settlement agreement associated with both Alternatives A and B, comparatively against other programs that you have observed to be a very aggressive set of protections, conditions, reviews, et cetera?

A. Yes, in particular the earnings test and the rate limit are among the most aggressive that I have seen.

MR. GRANT: Okay. Thank you very much, sir.

ACALJ NODES: Mr. Hogan.

MR. HOGAN: No questions.

ACALJ NODES: All right. Ms. Zwick, any questions?

MS. ZWICK: No questions.

ACALJ NODES: Ms. Vohra.

MS. VOHRA: Thank you, Your Honor.

CROSS-EXAMINATION

BY MS. VOHRA:

Q. Good afternoon, Mr. Cavanagh.

A. Good afternoon.

Q. In your direct testimony you state that Alternative A is inconsistent with the Commission's policy statement regarding decoupling, is that correct?

A. That's my view.

Q. And you participated in the general docket that culminated in the production of that policy statement, is that correct?

A. Yes.

Q. Doesn't the Commission's policy statement also state that the Commission could consider alternatives to full revenue decoupling?

A. It does. And then it goes on to say that full decoupling is preferable to partial decoupling for reasons that I agree with. And on pages 4 and 28, it specifically calls out problems associated with lost revenue recovery mechanisms, which I also agree with.

Q. And in your direct testimony you also state that Alternative A would undercut the whole purpose of the mechanism while creating perverse incentives, is that correct?

A. Back to the perverse incentives, yes, that's correct.

Q. And you are referring to Alternative A's lost fixed cost recovery mechanism?

A. Yes.

Q. However, NRDC agrees that both Alternative A and B are in the public interest, is that correct?

A. NRDC will support the settlement whether Alternative A or Alternative B is adopted, but I hope I have given you cause for why we so strongly prefer Alternative B.

Q. You have. However, would you agree that Alternative A is in the public interest?

A. I would agree that the entire settlement, including Alternative A, is in the public interest compared to continuing with the status quo, which is the worst of all worlds.

MS. VOHRA: Okay. Thank you. I have no further questions.

ACALJ NODES: Okay. Mr. Pozefsky.
MR. POZEFSKY: Thank you.

CROSS-EXAMINATION

BY MR. POZEFSKY:
Q. Good afternoon, Mr. Cavanagh.
A. Good afternoon.
Q. Let me see if I have got this straight. Alternative B will not raise the customer's bill more than a nickel?
A. A nickel a day for the average residential customer, that's right.
Q. RUCO's proposal would discourage energy efficiency?
A. It would do so by shifting more of the bill into a fixed charge and remove part of the bill from the variable charge, yes.
Q. Alternative A is inconsistent with the Commission's policy?
A. Because it represents partial decoupling, and the Commission has indicated a preference for full decoupling.
Q. Let's go back, Mr. Cavanagh. In your direct testimony in this case you also supported the company's efficiency enabling provision, correct?

A. Yes.

Q. Didn't have any conditions, just full out supported that, correct?

A. I full out supported it because it clearly reflected conditions that the Commission itself had established in the policy statement, yes.

Q. Familiar with Mr. Dismukes' testimony?

A. Yes.

Q. Let me read you what Mr. Dismukes says with regard to the company's energy enabling provision. And I am reading from page 9.

The proposed efficiency enabling provision mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the company and its shareholders and onto ratepayers. Such a shifting of risk without any corresponding mitigation or ratepayer protection measures will result in rates that are not fair, just, and reasonable.

If you are as concerned as you claim, Mr. Cavanagh, with consumers' interests, aren't you concerned with what Mr. Dismukes said with regard to the shifting of risk?

A. Mr. Dismukes is mistaken, in my opinion, in large measure because he fails to understand that by adopting a revenue per customer mechanism as the Commission recommended in its policy statement, the company is by no means insulating itself from economic risk.

Moreover, as I tried to explain in reviewing the relative merits of, quote, paying them for things they weren't actually contributing to, I don't think that that's what this is about at all. I think it is removing an automatic penalty inflicted on the company every time customers use less natural gas, and I don't think that's in the public interest or in customer's interest.

Q. So the ratepayer protection measures that Mr. Olea defines with regard to the settlement agreement --

A. Right.

Q. -- the idea of rate stability, you have all the reporting requirements, all of that is really unnecessary, correct? I mean, ratepayers are still being protected?

A. I supported the original proposal. I support the settlement, recognizing that there were a number of belts and suspenders that had to be added to get a very important party into the settlement. And I still support it.

Q. But again, they are all unnecessary really. I mean, like you said, the company's original EEP mechanism was sufficient to provide ratepayers protection, correct?

A. I supported the company's additional proposal and I support the proposed settlement, including Alternative B.

Q. Let's go to your settlement testimony, Mr. Cavanagh.

A. Sure.

Q. Could you go to page 3, please.

A. Yes.

Q. You state, and I am looking at on line 4, basically that you are strongly against adopting proposed Alternative A as a partial revenue decoupling, excuse me, as Alternative A fails to break the linkage between Southwest's financial health and retail sales, and seeks instead simply to restore lost revenues associated with energy savings determined to have resulted from the utility's, quote, achievement of the Commission's required energy savings, unquote.

A. Yes.

Q. Isn't that the exact thing that the Commission is trying to do?

A. No. What the Commission is trying to do is to remove a potent financial disincentive that is preventing a full partnership between Arizona utilities and their customers in the most aggressive energy efficiency campaign in the state's history. It is not simply trying to restore lost revenues from the utility's own energy efficiency programs.

And that distinction was a crucial part of the conversation throughout the workshops, and is clearly captured in the portions of the policy statement that I referenced earlier at pages 4 and 25, and then in the Commission's conclusion that full decoupling is preferable to partial decoupling. What you are describing is partial decoupling.

Q. Well, the partial decoupling proposal, Alternative A, which you oppose, one aspect is the Staff's proposed lost cost recovery mechanism, correct?

A. Yes.

Q. And again, you stated that this proposal is against or inconsistent with the Commission's policy. But if we go to paragraph 13 of the Commission's policy, it is on page 31 --

A. I have it.

Q. -- it says: Decoupling adjustments applied in a manner to encourage energy efficiency are preferred.

Isn't that, again, what the lost cost recovery mechanism was designed?

A. No, no. You stopped reading before the sentence ended: such as applying decoupling surcharges to rates and higher usage blocks to encourage energy efficiency. That goes back to my point about the Commission's clear direction to link decoupling with conservation oriented rate structures, and I agree entirely with that.

Q. Let's go to page 4 of your testimony. Again, I am on your settlement testimony.

A. Yes.

Q. You state: I emphasize my view that all partial decoupling like that of Alternative A would undercut the whole purpose of the mechanism.

Are you claiming that all partial decoupling mechanisms -- or I am trying to determine whether any partial decoupling mechanism would not exactly do that, would not undercut the whole purpose. Is it just this partial decoupling mechanism or just about any decoupling mechanism?

A. Well, I think lost revenue recovery is particularly problematic for reasons that the Commission itself calls out in the policy statement. I feel less strongly, for example, on the electric side many so-called partial mechanisms include weather normalization. There was some discussion of this with

Dr. Hansen.

I think the right answer lies in providing customers with relief from extreme weather events and in this Commission's policy statement proposal, which is also consistent with the vast majority of the states, is the right way forward, but that strikes me as a less perverse way of addressing decoupling than the lost revenue recovery mechanism.

Q. And you -- you continue to go on in that paragraph, I am not going to read through it, but what I think I am reading or what I am gathering from your testimony is under Option A utilities will not recover pretty much as much of its fixed cost as under Option B. Is that a fair statement?

A. No. And this is perhaps an important point to -- for me to emphasize. Under Option B there will be years when utilities give money back to customers. One of the happy features of full decoupling is that the adjustments go both ways. Option A will be an automatic annual rate increase, and from Southwest's perspective in some ways might even be preferable, but not from mine.

Q. How would it reintroduce automatic penalties?

A. Well, it does two things. First all, there are automatic rate increases, because Southwest will always, we presume, achieve some efficiency and, therefore, will qualify for some lost revenue recovery, the automatic penalties will come whenever consumption drops for other reasons like, for example, as came up earlier, improvements in federal efficiency standards for appliances or state efficiency standards for buildings. Every time those standards kick in, or every time local government gets better at helping people build more efficient homes, there will be an automatic penalty because you don't have full decoupling. Every reduction in sales hurts the company under Alternative A.

Q. You also -- and I have heard this term a couple of times -- say that Alternative A would create a powerful and perverse new incentive for the company.

A. Yes.

Q. What exactly -- give me an example of an energy efficiency program that would actually be encouraged by the company, but would be perverse to what you are thinking.

A. And Dr. Hansen mentioned the company's incentive then is to introduce the most aggressive, optimistic engineering estimates it can find for savings delivered by every conservation program it brings forward. The company's incentive is to try through every clandestine means possible to minimize the enduring character of the savings, because if it is successful in promoting programs that look good on paper and don't save any energy, it will recover twice. It will get the lost revenue adjustment and then it will get the actual revenues which were never in fact lost. And I just think that's the wrong way to go into this. Revenue decoupling avoids that problem.

Q. But wouldn't that be inconsistent with the company's requirement to meet its energy efficiency goals?

A. Yes, it would. And I do not assume for a moment that this company's management would instantly fall victim to all of the vagaries of bad incentives.

But all things considered -- and I think this is a fundamental message from the Commission's policy statement -- given the aggressiveness of our efficiency aspirations for Arizona, let's try to do a better job of getting the incentives right going in, as opposed to effectively trying to force the utility to march uphill the whole way.

Q. Is that why you concluded that Alternative A would leave unimpaired strong utility incentive to promote increased natural gas use?

A. Certainly, because every increase in consumption per customer that the utility can achieve or in any way facilitate will go right to the bottom line. They will keep it.

Q. So that is directly counter, the exact opposite of the whole purpose of energy efficiency --

A. Exactly.

Q. -- would you agree?

A. That's why we don't like Alternative A.

Q. So how is Alternative A in any form in your opinion in the public interest?

A. It is better than the status quo.

Q. How?

A. The status quo provides all of the adverse consequences associated with increased consumption, and does nothing to incent the company to deliver energy efficiency. So at least under Alternative A there is a compensation structure established which can be worked out over time. We don't think that it is the right one, we think it is far from ideal, but it is better than nothing at all.

Q. So right now, Dr. Cavanagh, the -- Mr. Cavanagh --

A. You are giving far too much precedence to a law degree. Go ahead.

Q. Right now, Mr. Cavanagh, under the current system as we have it, is it your testimony that the utility incentive at this point is to promote increased gas usage?

A. Yes. Without having a decoupling it was also the Commission's finding in the policy statement on removing disincentives to energy efficiency.

Q. And the only way to provide the incentive to get the company in line with energy efficiency is full revenue decoupling?

A. I agree with the Commission's statement that full revenue decoupling is the preferred course, yes.

Q. Under Option B, Mr. Cavanagh, what is the purpose of allowing the company to recover costs not associated -- or excuse me, revenues not associated with energy efficiency?

A. Let's again be very clear. Alternative B does not allow the company to recover revenues not associated with energy efficiency. All it does is to say that the revenue requirement that the Commission approved, the recovery of that revenue requirement won't be affected by changes in natural gas use. That's a very different statement.

We are not paying the company for changes associated with the economy or anything else. We are simply making recovery of the previously approved revenue requirement independent of fluctuations in natural gas use. That is very different.

Q. Well, that's clearly not linking the recovery to energy efficiency, though, is it?

A. It is delinking the recovery from changes in consumption and specifically making sure that increases in consumption don't boost recovery above authorized levels, which I would hope all of us could agree is a good thing.

Q. Let's go to page 6 of your settlement testimony. Now we are talking about Alternative 3?

A. Yes.

Q. You state, Alternative 3 is appealing because it reduces risks for both customers and Southwest.

A. Yes.

Q. Let me stop right there. So you will admit that reduces risk to the company?

A. Some risks, yes; it increases others.

Q. You also talked about all the states -- you stated that, I think, 22 states have experienced or are experiencing revenue decoupling, correct?

A. For natural gas, yes.

Q. So that means 28 states aren't?

A. That's right. It is a work in progress.

Q. How many of those 22 states have full revenue decoupling?

A. Oh, on my count all 22 have full revenue decoupling. I am only counting states with full revenue decoupling. There are a few examples, as Dr. Hanson indicated, of other approaches. But I don't count, for example, straight fixed variable rate design as full decoupling.

Q. Are you familiar with the decoupling experience that the State of Maine had in the 1990s?

A. In the early 1990s for electricity, yes.

Q. You are aware that they did have a decoupling regime or decoupling methodology --

A. Yes.

Q. -- in the early 1990s, right?

And since then that decoupling was a disaster for the most part, wouldn't you agree?

A. No. Would you like to know what happened?

Q. Yeah, I would.

A. The State of Maine adopted revenue decoupling for its electric utility, Central Maine Power, and did so at the beginning of a severe recession which lasted for several years. The mechanism didn't have rate impact caps, but it also didn't have assurance that the balance would be cleared annually.

And what the Maine commission did, instead of allowing the decoupling adjustments to proceed, was to let the balance ride. The balance over three years became larger than the commission found politically manageable in terms of a rate adjustment, and at that point the commission, with the recession still on, jettisoned the mechanism.

The decisive difference between what Maine did from roughly, I think, '90 to '93 and what we are proposing here lies precisely in the rate impact protections, and also in the assurances that these adjustments will occur on a regular basis. There is no potential for balances to accumulate. The books will be cleared on a regular basis.

And the final difference between this mechanism and the Maine mechanism is that this mechanism is adopted in the wake of, remember, again, experience with 22 different states, 88 different rate adjustments as evaluated by Pamela Lesch in her assessment, which was a big part of the Commission's workshops. And what those findings show is that you can run a natural gas mechanism responsibly with the rate cap that amounts to less than 5 cents per average residential customer per day. That's what is before you here, not the Maine mechanism from the early 1990's for electricity.

Q. What about Tennessee? They recently just rejected a decoupling, a full revenue decoupling proposal. What's the difference?

A. And over the course of the last 20 years commissions have come out in different places on this issue. Mr. Dismukes is active in many states. Sometimes the opponents prevail.

I would say that the decisive difference between Tennessee and here is that this Commission undertook the inquiry that led to the policy statement in December of 2010. Nothing comparable to that has ever happened in Tennessee. I think this Commission was right, and I think the Tennessee commission, when it rejected one decoupling mechanism, although it approved a different one, was mistaken.

Q. What about Washington? Hasn't Washington stated a preference for partial decoupling over full decoupling?

A. Yes, for natural gas. Washington state has stated a preference for partial decoupling. And I think Washington is mistaken, and I think this Commission's policy statement is the right course.

But partial decoupling for natural gas is very much the minority view in terms of what is happening around the country. And I didn't count any of the partial decoupling mechanisms in my 22 state total.

Q. What about Connecticut?

A. What about Connecticut?

Q. I am just going back. I am not familiar with all the states that have rejected it, but I thought Connecticut --

A. No. Insofar as I know Connecticut, and I think Dr. Hansen is more familiar with Connecticut than I am, but my understanding is, Connecticut at the moment has a state policy in favor of full decoupling. And certainly, on the natural gas side, there has been some controversy about it, there have been some arguments about it.

But I am certainly not aware of anything happening in Connecticut or any other state with an experience with full decoupling for natural gas that has resulted in adverse consequences for customers. And I didn't see anything in the record of this proceeding to change that view.

Q. And if you were aware you would tell us, right?

A. Oh, yes.

Q. Sure. All right. Thank you.

A. No, the worst story is the Maine story. And it is a very old story.

MR. POZEFSKY: Thank you, sir.

ACALJ NODES: I have just a few questions, Mr. Cavanagh.

EXAMINATION

BY ACALJ NODES:

Q. You were talking to Mr. Pozefsky about risk.

A. Yes.

Q. And I believe you said that with full decoupling certain risks will be decreased --

A. Yes.

Q. -- but others would be increased. Could you explain what you mean by that?

A. Yes. And there is a reason, Judge, why the entire utility industry hasn't reached out to embrace revenue decoupling. And it has to do with the loss of an upside, particularly at a time when I think all of us devoutly hope that the country is poised on the edge of a significant economic recovery.

If you move to full revenue decoupling in 2011 you are kissing good-bye the upside associated with that recovery in terms of increased use of natural gas and electricity. And it is the loss of that upside that has persuaded many utility managements, as my RUCO colleague correctly points out, they don't want to move ahead with revenue decoupling right now.

My testimony includes a recent study by the Brattle Group looking at whether the cost of capital to natural gas utilities has gone up or down as a result of revenue decoupling. And what the study finds basically is they can't, they don't -- they certainly don't see any reduction, and they see some evidence of a very modest increase. That's not helping me sell this with utility managements, either.

Q. Okay. So that's -- would you agree that the biggest risk faced by natural gas companies that are experiencing declining use per customer, declining revenues per customer --

A. Right.

Q. -- over the past decade or more, that the risk if decoupling, full decoupling is implemented, that would remove the biggest risk that is faced by those utilities?

A. Unless, Judge, unless the Commission -- as it may well do in this case -- reduces the authorized revenue requirement for the utility in anticipation of that trend continuing. And for that reason the settlement proposal, Judge, does not reflect the level of revenue recovery that the utility originally sought. And I am sure that Staff was vigilant and forceful on that point in part because of precisely the trend you identify.

The utility number may have made sense in light of current trends. The Staff number likely makes more sense in light of projected reductions in consumption.

But, Judge, also recognize that this is a moment, if, if one, as I know we all do, thinks and hopes that we are coming out of this at some point, if adopting revenue decoupling at the base of the trough in terms of the economy is tough timing, even in an industry which has a history of reductions in per customer use, they might reasonably expect that to perk up a little over the next several years, and we are not letting them.

Q. Okay. Well, if, and however, if rating agencies are believed to accurately assess risk associated with a given company's operations, you would agree that companies that have full decoupling are considered to be less risky than those without?

A. Judge, on that point, again I think the Brattle Group's study is instructive, because, while I am tempted to, one, agree with what you just said because it was very close to being a rhetorical question, it is instructive that there is no evidence that the decoupled utilities are actually experiencing lower cost of capital in the field. And what that may signal is that other factors, like disappointment at the loss of the upside, are also relevant here.

If this were a slam dunk for utility management, utilities across the country would be clamoring for revenue decoupling. They are not.

Q. You don't think Southwest Gas has been clamoring for revenue decoupling for the past decade?

A. Judge, I would like to think that perhaps energy efficiency advocates had a little to do with that. And I have, certainly. It has been a longstanding subject of conversation. It is not for the last decade, either. My engagement with Southwest on this doesn't go back nearly that far. I think it is fair to say that the gas industry's engagement on this, in my experience, really became substantial in the mid 2000s, about '04 to '06 period, and it coincided with an industry wide sense that they wanted -- I don't think this is in any sense totally altruistic -- they wanted to get those improvements in customer ratings that come with strong efficiency records.

And I think Dr. Hanson's finding there have spoken powerfully to management. At that point, if you are tying to your future to efficiency and to partnerships with customers on efficiency, then, yes, I think you will want revenue decoupling. But the whole industry isn't there yet.

Q. And isn't the company's position in that regard also influenced by feedback from the rating agencies, that companies should seek revenue decoupling because of the lessened risk associated with the revenue stream?

A. And there, Judge, as someone who has gone hat in hand, when I had a hat, to Fitch, Standard & Poors, and Moody's pleading with them to be more aggressive in advocating changes in utility business models, I would have to say that my own view of where the rating agencies' are is that acceptance is at best grudging. We are in a better position than we were a few years back, but it is not like it is the top of their list.

So I am gratified to see -- and there is evidence of it in the record -- that rating agencies like Moody's have come around and on the whole accepted revenue decoupling as a plus. It is still not showing up in actual cost of capital in the market.

And, Judge, the final thing to say about this I think, if your view at the end of the day is that full revenue decoupling should come with a reduction in authorized return on equity, the settlement offers 25 basis points which is at the high end of all of the targeted reductions that have been imposed in the conjunction of gas revenue decoupling.

So if that's your view, the settlement offers it. I would not have offered it if it were my druthers, because I don't think that all of the essentials are there to justify it, but it is in the settlement proposal. Just say yes.

Q. I am just trying to create a full record so the Commission will be able to make an informed decision. I am not advocating one way or the other. And I am sure I hope you see that when RUCO's witnesses get on the stand I will be asking them tough questions as well.

A. I know you will.

Q. I am not sure I totally agree that the rating agencies aren't influencing company management decisions based on things that I have seen and read in evidence, though.

A. But you do remember at the moment the count. And this skeptical question is correct. 28 states still don't have gas revenue decoupling, and for electricity it is more like 36. So it is still a minority view. It is now well enough established so I think all the rhetoric about uncharted and dangerous waters is overstated, but it is still not the industry norm.

Q. Okay. And just one other area. You would agree that with full decoupling, a customer who either cannot conserve because they are unable or unwilling to in order to reduce his or her bill is going to pay a higher amount on the non-gas portion of the bill under decoupling than under a mechanism that does not include the decoupling?

A. I don't agree for two reasons. First of all, it depends on what everyone else does, because you will only pay more if everyone else uses less. And second, this is to return -- the benefits I think go beyond short-term individual gas consumption reductions or increases. I agree with what Dr. Hansen said about the importance of reducing overall volatility in natural gas prices by constraining total consumption.

I also think that there are infrastructure savings on the natural gas side. I have just completed service on a natural gas task force, the bipartisan policy center, that was looking at concerns about shortages in natural gas storage, in shortages in pipeline delivery capacity. There are infrastructure implications associated with natural gas consumption in addition to the gas use for each household and business, and in addition to the potential positive effects of overall reductions in consumption on natural gas price volatility. There are system benefits that everyone shares.

Q. Okay. But they are not even in the ball park --

A. Of five cents a day?

Q. No, no. Not compared to the electric industry, the infrastructure savings are not in any way comparable?

A. I don't think they are as large. I actually don't think there has been a rigorous assessment. Qualitatively, though, the savings I just mentioned are potentially significant, particularly the shifts in volatility, Judge, because natural gas historically has been a far more volatile commodity than electricity.

It you are looking at a world where you can go from $2 a million BTU to 50, which is a world we have all lived through, that is orders of magnitude different in terms of its implication for customers than the much more stable natural gas -- the much more stable electricity rate environment. That's a benefit worthy of more study, and hopefully we will learn about it together to the benefit of everyone in Arizona.

Q. And just one final question to return back to my question about the customer who is unable or unwilling to reduce --

A. Yes.

Q. -- usage relative to everyone else who you said you disagree because it depends on what --

A. Everyone else does.

Q. -- other people do. But if regardless of conservation efforts, if, as we have heard in this case, Southwest Gas is experiencing a trend, a significant trend of downward usage on a per customer basis, isn't it likely that the customer I spoke of or gave as an example, will in fact, experience a higher bill under decoupling than without decoupling?

A. No, Judge, and because you are leaving out one more crucial factor, which is I am -- and I think this is the most important thing for me to say to you and my guess is Mr. Schlegel will say it ever more eloquently, it is the linkage with efficiency and the bill reductions from efficiency that's at the heart of why we are doing this.

We are not just doing decoupling for decoupling's sake. We are doing it because we think it is the key that unlocks billions of dollars of reductions in customers' bills, both electric and natural gas. If we didn't think that, we would have no business making this case to you. And you have got to understand the customer perspective and the impact on bills from the combined perspective of efficiency and decoupling, not treating decoupling as if this were simply an isolated regulatory reform.

Q. So that customer putting aside --

A. Right.

Q. -- the entire long-term scope of ultimate savings due to systematic energy efficiency programs, you are saying on the record

A. Right.

Q. -- that an individual customer who does not reduce usage under full decoupling is not going to pay a higher amount on his or her bill compared to a nondecoupling regulatory environment?

A. Judge, he will, he or she will only pay a higher bill if other customers collectively reduce their consumption. So that's crucial.

Q. Well, wait a minute. I'll stop you there. Even if those customers do not conserve, reduced usage per customers due to other factors, including weather, would cause that phenomenon to occur, would it not?

A. And there, Judge, but if your concern is there, surely then the answer lies in your decision as to the authorized revenue requirement, which will take into account your expectations in terms of trends in per customer use. That's why it was reasonable, in my judgment, for Staff to insist on a reduction in the authorized revenue requirement, but that's, that's where that is supposed to be taken into account.

I think you are trying to solve, if the effort here is to anticipate an account accurately for secular trends in per customer reduction, the place to do it is in the authorized revenue requirement, not in the decoupling mechanism. And you build in an authorized recovery per customer that takes that into account. And I would argue the settlement does that.

ACALJ NODES: Okay. Commissioner Newman, I want to go to you, but we need to give the court reporter a break.

COM. NEWMAN: Just one question.

ACALJ NODES: That's fine. Then we are going to go to lunch.

EXAMINATION

BY COM. NEWMAN:

Q. First of all, it is good to see you again. Thank you for coming back and being a witness today. The judge was sort of alluding to it, and I know you stated some things, but I want to sort of take a macro economic view of prices instead of trying to say that not everyone -- well, in response to sort of the judge's question that saying not everyone could benefit under this.

I think it came out in the workshop, at least it has been something that I have talked about a lot, is that you mentioned natural gas storage, which we don't have any of in Arizona. We don't get our natural gas from Arizona, we import it. It is not a natural resource that we have -- we spent a lot of money getting it here. That's an issue for Arizona.

So with regard to these price fluctuations, ever since I have been following these issues, which is around 15, 20 years now, that has always been something that I have been interested in. Of course, and Enron's experience brought it to an exponential level of awareness with regard to what it did in California and all around the country with regard to gas prices.

And you mentioned it that the peaks and valleys during some of these times were more than individual families could even deal with. In fact, it almost took down the California economy at one point. I know that you know about that.

So my thinking on also doing decoupling is that long-term hedge on prices. Is there a macro economic cut that perhaps the AARP and other opponents are not thinking about as much regarding this being a hedge on long-term prices?

A. Absolutely. And the American Council for an Energy Efficient Economy has actually tried to quantify the value of the hedge. Fundamentally what you are doing is you are taking some of the pressure off a badly overstressed delivery and supply system. And there are measurable benefits in terms of reduced volatility over time to doing that. And I absolutely think that's one of the reasons for considering this proposal.

Q. And is there evidence in the record, or can we supplement it with any studies that you haven't put into the record yet with regard to that?

A. As I say, the ACEEE website is happily still a repository of at least two of these assessments, and we will be happy to do that.

COM. NEWMAN: I would ask that the record be supplemented with regard to that.

BY COM. NEWMAN:

Q. And that's really the best question. I wanted to also ask the same question in a different way, I mean, and I started doing it. We are a state devoid of natural gas. We have to pay for it. I know that some folks don't like me doing this. But if I view Arizona as an entity unto itself, a sovereign entity under the 11th amendment, I suppose it is, and so we, we are trying to do the best for Arizona, we are trying to do the best for the southwest, we are trying to do the best for the country given these tough economic times and energy scarcity. We are trying to produce more renewables here because we spend X amount of money, billions of dollars to purchase this gas and bring it here.

So if you can, just for the final question, provide sort of an overall nexus and sort of macro economic view not only how this is a good hedge against gas prices that we have to buy from out of state transport here, which costs all that more money, and the development of a healthy renewables market which many people believe in Arizona is one of the most promising of our job futures.

A. I am in full accord.

Q. Can you in your own words.

A. Well, I will note on the nexus between efficiency and renewables specifically, Commissioner, I think you will take heart from the portfolio of programs that Southwest has promised to bring forward which have strong efficiency and renewable elements.

I also think that to the extent we can reduce natural gas price volatility, that will be very good news for renewables, because it will reduce the cost of integrating variable output renewables.

Some people think that gas prices and renewables are a zero sum and that any good news on gas prices is bad news for renewables. And I don't believe that. I think that these are resources that move in tandem that have common interests that are going to end up being a crucial part of our electricity portfolio together, working together. And I think I agree with the way that you trace the connections that I have also tried to put forward in our testimony.

COM. NEWMAN: Thank you so much.

ACALJ NODES: Okay. Thank you.

Any redirect?

MS. SANCHEZ: Just one follow-up question, just to circle back to the settlement and to understand sort of where NRDC's position is and make it clear.

REDIRECT EXAMINATION

BY MS. SANCHEZ:

Q. You stated in terms of the support for the settlement, then, it's Option B over Option A, correct?

A. Yes.

Q. Option A over status quo?

A. Yes.

Q. Where does the RUCO proposal, the customer charge, does it rate into that? Or is that just sort of -- how would you rate that as a recommendation, based on your experience, for the Commission?

A. My view is that increasing the fixed charge is a bad idea and actually would make things worse. So I certainly hope we don't go there.

MS. SANCHEZ: No further questions, Your Honor.

ACALJ NODES: Any additional questions for Mr. Cavanagh?

(No response.)

ACALJ NODES: Okay. Thank you for your testimony, sir. You are excused.

THE WITNESS: Thank you.

ACALJ NODES: All right. We are going to take a lunch break until 2:15, and we will return with Mr. Schlegel. And then just, I had written down we have Ms. Zwick and Mr. Yaquinto as the two other possible witnesses, but I don't know if anyone else has any other ideas on that.

MR. GRANT: Mr. Yaquinto can go if we have time.

MS. MITCHELL: If we have time we can go to Ms. Keene.

ACALJ NODES: Ms. Zwick is here so maybe we will count on Ms. Zwick after Mr. Schlegel. Okay. Great.

(A recess ensued.)

(Colette E. Ross, Certified Reporter, was excused from the proceedings.)

(TIME NOTED: 1:11 p.m.)

SWEEP Direct

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
SWEEP-1

COMMISSIONERS

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-11-0224

Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

November 18, 2011

Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-11-0224

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Please describe the Southwest Energy Efficiency Project (SWEEP).

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting customer benefits, economic prosperity, and environmental protection in the six states of Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. SWEEP works on state legislation; analysis of energy efficiency opportunities and potential; expansion of state and utility energy efficiency programs as well as the design of these programs; building energy codes and appliance standards; and voluntary partnerships with the private sector to advance energy efficiency. SWEEP collaborates with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency. I am the Arizona Representative for SWEEP.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency programs and clean energy resources. I consult for public groups and government agencies; and I have been working in the field for over 25 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997 I received the Outstanding Achievement Award for the International Energy Program Evaluation Conference. I have testified before the Arizona Corporation Commission in many proceedings.

Q. What is the purpose of your testimony?

A. In my testimony, I will summarize the public interest in increasing electric energy efficiency; discuss why and how the Commission can increase energy efficiency opportunities to help Arizona Public Service Company (APS) customers reduce their utility bills; describe how the Company has positioned energy efficiency to become the primary energy resource to meet energy growth over the next decade; explain why energy efficiency, as a fundamental energy resource meeting the real energy needs of customers at lowest cost, must be satisfactorily funded and provided stability by expensing a majority of energy efficiency program funding in base rates; recommend a new energy efficiency performance incentive that will better promote delivery of cost-effective energy efficiency and associated public interest benefits; stress the need for the Company to document reductions in utility system and customer costs as a result of energy efficiency and as a means to demonstrate the value of energy efficiency investments; discuss the linkage between the increased utility efforts in energy efficiency and the adoption of decoupling; comment on and support – with two exceptions – the decoupling mechanism (Efficiency and Infrastructure Account or EIA) proposed by the Company to reduce the financial disincentive to utility support of energy efficiency; propose a methodology to better account for the impacts of Commission-adopted energy efficiency policies in determining rates; describe SWEEP's support for redesigning the bill in order to lessen customer confusion and provide customers with more useful information; and urge Commission disapproval of the Company's proposed infrastructure tracker (Environmental and Reliability Account).

The Public Interest in Increasing Electric Energy Efficiency

Q. What is the public interest in increasing electric energy efficiency?

A. Electric energy efficiency is in the public interest. Increasing energy efficiency will provide significant and cost-effective benefits for all APS customers, the electric system, the economy, and the environment. Electric energy efficiency is a reliable energy resource that is less expensive than other available energy resources. Consequently, increasing energy efficiency will save consumers and businesses money through lower electric bills and the deferral of unnecessary infrastructure, resulting in lower total costs for customers. Increasing energy efficiency also reduces load growth; diversifies energy resources; enhances the reliability of the electricity grid; reduces the amount of water used for power generation; reduces air pollution; creates jobs that cannot be outsourced; and improves the economy. In addition, meeting a portion of load growth through increased energy efficiency can help to relieve system constraints in load pockets. By reducing electricity demand, energy efficiency mitigates electricity and fuel price increases and reduces customer vulnerability and exposure to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply or increased prices for natural gas or other fuels.

Q. What are the estimated costs for energy efficiency savings?

A. Energy efficiency is a reliable energy resource that costs significantly less than other resources for meeting the energy needs of customers in APS' service territory. In 2010, the cost of energy efficiency programs including measurement evaluation and research (MER) and the Company performance incentive was $0.142 cents per lifetime kWh.[1] In 2011, the planned program costs including MER and the Company performance incentive is projected to be $0.185 per lifetime kWh.[2] According to the testimony of APS witness Leland Snook, the cost of energy efficiency programs will be approximately $0.035 per kWh in 2015[3]. In comparison, the 2010 cost of new generation for other energy resources is substantially more: natural gas combined cycle generation costs between $0.082-$0.156/kWh; coal generation costs between $0.101-$0.189/kWh; and nuclear generation costs between $0.14-$0.215/kWh.[4]

Increasing Energy Efficiency to Reduce Utility Bills for APS Customers

Q. What should the Commission do to increase opportunities for APS customers to reduce their energy bills through energy efficiency?

A. In its order on the APS rate case, the Commission should require APS to meet the energy savings requirements in the Electric Energy Efficiency Standard ("EEES"); ensure that there is adequate funding to achieve the EEES energy savings requirements and attain the associated public benefits; and treat energy efficiency as the core energy resource that it is by expensing the majority of the energy efficiency program funding in base rates.

Q. What energy savings requirements should the Commission set?

A. The Commission, in approving any order that increases rates for APS customers, should ensure that the least cost resource – energy efficiency – is fully pursued, consistent with the Commission-adopted EEES, which established cumulative annual energy savings requirements to make certain that energy efficiency and all of its associated public interest benefits would be realized. Accordingly, the cumulative annual energy saving requirements set forth in the EEES should be included in any Commission order increasing APS rates. The cumulative annual energy savings requirements in the EEES are listed below (expressed as cumulative annual energy savings as a percent of retail energy sales in the prior calendar year):

- 2012: 3.00% cumulative annual energy savings
- 2013: 5.00% cumulative annual energy savings
- 2014: 7.25% cumulative annual energy savings
- 2015: 9.50% cumulative annual energy savings
- 2016: 12.00% cumulative annual energy savings
- 2017: 14.50% cumulative annual energy savings
- 2018: 17.00% cumulative annual energy savings
- 2019: 19.50% cumulative annual energy savings
- 2020: 22.00% cumulative annual energy savings

[1] Arizona Public Service Company Demand Side Management Semi Annual Report, July through December 2010.
[2] Arizona Public Service Company's 2011 Demand Side Management Implementation Plan Application.
[3] Western Resource Advocates data request 1.3
[4] Leland Snook work paper 3.

The cumulative annual energy saving requirements set forth in the EEES result in approximately the following levels of annual energy savings (expressed below as approximate annual energy savings as a percent of retail energy sales in the prior calendar year):

- 2012: 1.75% annual savings
- 2013: 2.00% annual savings
- 2014: 2.25% annual savings
- 2015: 2.25% annual savings
- 2016: 2.50% annual savings
- 2017: 2.50% annual savings
- 2018: 2.50% annual savings
- 2019: 2.50% annual savings
- 2020: 2.50% annual savings

Q. Has the Commission included energy savings requirements for energy efficiency programs in a rate case order for APS previously?

A. Yes. In APS's last rate case, the Commission similarly ordered the Company to achieve annual energy savings for customer benefit in 2010, 2011, and 2012. The Commission required APS to achieve annual energy savings from energy efficiency programs of 1.0% in 2010, 1.25% in 2011, and 1.5% in 2012, expressed as a percent of total energy resources needed to meet retail load.

In 2010, APS surpassed this 1.0% savings requirement, achieving savings equivalent to 1.05% of total energy resources. As a result of the energy efficiency programs it implemented in 2010 to meet this requirement, APS delivered more than $150 million in net benefits for customers; produced annual savings in excess of 300 GWh; generated lifetime savings in excess of 3.5 TWh; conserved more than 1 billion gallons of water; avoided more than 7 metric tons of sulfur oxide emissions; and prevented more than 130 metric tons of nitric oxide emissions.

In 2011, the Company is implementing programs that are on track to meet the 2011 savings requirement of 1.25%: as of June 2011 APS had already delivered more than $76 million in net benefits; produced annual savings in excess of 200 GWh; and generated lifetime savings in excess of 2.0 TWh. APS has also proposed an energy efficiency implementation plan for 2012 (currently pending before the Commission), which if approved, is designed to achieve the 2012 savings requirement of 1.5% and deliver substantial public interest benefits.

Q. How can adequate funding to achieve the EEES energy savings requirements be ensured?

A. APS has positioned energy efficiency to become the primary resource to meet energy growth over the next decade. From 2011 to 2020, energy efficiency will meet more than half of APS' planned energy growth, making it the Company's largest growing energy resource for meeting load growth over the next ten years. As a fundamental resource meeting the real energy needs of customers at lowest cost, energy efficiency must be satisfactorily funded and provided stability – else the numerous public interest benefits of this core resource may not be realized. In order to provide adequate treatment for this central resource, it is critical that a total of $70 million of energy efficiency programs be expensed in base rates. Since $10 million of energy efficiency program funding is already expensed in base rates, a $60 million increase would be necessitated. The demand side management (DSM) adjustment mechanism should still remain intact, but should recover or refund any energy efficiency funding amounts above or below $70 million, as needed to implement energy efficiency programs to meet the energy savings requirements established by the EEES. In this way, the DSM adjustment mechanism would serve as a flexible means of recovering additional program funding (as needed).

Q. Has the Commission allowed energy efficiency program funding to be expensed in base rates previously?

A. Yes. In Commission Decision No. 67744, approving the settlement agreement to increase APS rates in 2005, an annual $10 million allowance for DSM costs was approved for inclusion within base rates. In 2006, the year directly following that decision, the Company spent $10.6 million on energy efficiency programs. Thus the $10 million allowance equated to more than 90% of energy efficiency program expenditures in that year. Since this time, energy efficiency has evolved to become a central energy resource meeting the real energy needs of customers at lowest cost while also delivering substantial benefits for customers, the economy, the utility system, and the environment. Moreover, as described earlier, APS has positioned energy efficiency to meet more than half of APS' planned energy growth over the next decade, making it the primary energy resource for meeting growth over the next ten years. As a core and growing component of the Company's energy resource mix and also the least expensive resource available to meet future energy needs, energy efficiency must be adequately funded and provided consistency. In its 2012 plans for energy efficiency, the Company proposes to spend $78 million on programs while delivering $194 million in net benefits to customers. Hence, expensing $70 million in base rates would equate to approximately 90% of these anticipated funds.

Q. What else should be done to increase opportunities for APS customers to reduce their energy bills through energy efficiency?

A. In addition to adequate funding for program implementation and delivery, energy efficiency programs must continue to be cost-effective, efficient, and successful and should continue to be reviewed, approved, and improved through the energy efficiency implementation plan and the semi-annual reporting processes. It is also essential that the Company continue to expand and diversify offerings so that a larger number of customers can achieve greater energy and bill savings and that it continue to develop innovative approaches to leverage ratepayer money with funds from other sources. For example, the Company should continue to expand savings opportunities for small businesses and renters available through its Small Business and Multifamily Energy Efficiency programs, respectively; fully implement an energy efficiency financing offering for small businesses; expand its Consumer Products offerings to include additional equipment, including electronics; jointly offer and deliver programs with gas utilities as a means to achieve program delivery efficiencies and cost savings and to provide gas and electric customers with more savings opportunities and a more seamless experience; and develop programs highly tailored to certain market segments (i.e. hotels, retail stores, large multifamily properties, data centers, etc.).

Energy Efficiency Performance Incentive

Q. What is SWEEP's proposal for an energy efficiency performance incentive in this rate case?

A. Energy efficiency performance incentives have been shown to be an important tool to encourage effective delivery of cost-effective energy efficiency, and SWEEP supports appropriately designed performance incentives.

In SWEEP's view an appropriately designed performance incentive:

1. Encourages the Company to pursue cost-effective energy efficiency;

2. Is designed in such a way to avoid any perverse incentives;

3. Is based on clearly-defined goals and activities that are sufficiently monitored, quantified, and verified;

4. Is available only for activities for which the Company plays a distinct and clear role in bringing about the desired outcome; and

5. Is kept as low as possible while balancing and meeting the objectives and principles mentioned above.

SWEEP proposes that the Company's current performance incentive — a tiered performance incentive as a percentage of net benefits, capped at a tiered percentage of program costs — should be improved to be more effective while reducing any perverse incentives. To that end, SWEEP proposes that the Company's energy efficiency performance incentive be redesigned so that it simultaneously incents cost-efficiency and the delivery of a high volume of savings.

Q. What improvements in the Company's performance incentive does SWEEP propose?

A. SWEEP proposes changes to the performance incentive cap and the design of the incentive mechanism.

First, SWEEP recommends that the performance incentive cap be determined based on a percent of the goal and target incentive amount rather than on a tiered percentage of program costs. Specifically, for a performance incentive based on meeting a certain goal, for which the Company would earn 100% of its proposed incentive by meeting the target of 100% of goal, the performance incentive amount would be capped at 130% of the target incentive amount (which would be commensurate to performance at 130% of goal). For example, consider a goal of X, with a target performance incentive of Y. If the Company performs at 140% of goal (140% of X), the Company's performance incentive amount would be capped at 130% of the target incentive amount (130% of Y). The performance incentive cap would not be based on what the Company spent.

Second, SWEEP proposes a three-component performance incentive mechanism designed to encourage the company to achieve benefits for customers (the volume of benefits), to achieve the customer benefits cost-efficiently from the perspective of ratepayers (thereby enhancing value to ratepayers), and to focus on specific indicators of performance for certain key objectives or in specific market segments. Specifically, the performance incentive mechanism should consist of three components:

1. Benefits component, based on the present value (in dollars) of the achieved societal benefits of the program (45% of the total incentive amount).
2. Cost-efficiency component, based on the achieved total societal benefits minus the program costs funded by ratepayers (45% of the total incentive amount).
3. Specific performance metrics focused on specific indicators of performance for certain key objectives or in specific market segments, such as metrics for performance on financing offerings or performance in specific segments such as low income customers, multifamily customers, or small businesses (10% of the total incentive amount). The specific performance metrics should be able to be proposed, updated or modified in an energy efficiency implementation plan process.

SWEEP recommends that the performance incentive cap described above be applied to each component and metric in the performance incentive.

<u>Documentation of Utility System Cost Reductions as a Result of Energy Efficiency</u>

Q. How can the Commission ensure that investments in energy efficiency are reducing customer costs and the forecasted costs of the utility system?

A. As APS increases the energy efficiency investment, it must demonstrate the value of this investment in delivering public interest benefits, including reductions in utility system costs and customer costs over time as a result of lower customer loads on the utility system. As part of this rate case and in subsequent reports, APS should document in its filings before the Commission reductions in forecasted or planned costs in meeting the needs of customers and their forecasted loads, including deferral of plant investments and a lower level of plant investments, as a result of energy efficiency expansion as required by the EEES. The Company should also include document such utility system cost reductions as a result of increased energy efficiency and reduced customer loads in its demand side management reports.

Decoupling to Reduce the Financial Disincentive to Electric Utility Support of Energy Efficiency

Q. Does APS experience a financial disincentive to its support of energy efficiency when its customers respond and become more energy efficient?

A. Yes. Traditional utility regulation links the utility's financial health to volumetric sales of electricity, resulting in a utility financial disincentive to support energy efficiency and other demand-side resources that reduce sales. Energy savings by APS customers (which are beneficial for customers, the economy, the utility system, and the environment) result in lower revenues for the Company and the under-recovery of Commission-authorized utility fixed costs. In general, this financial disincentive can reduce utility support and enthusiasm for cost-effective resources such as energy efficiency programs that minimize the long-term costs of providing service. It could also impede potentially crucial utility support for building energy codes and other policies that reduce utility bills for customers and serve societal interests.

Q. Should a decoupling mechanism for APS be implemented to reduce the financial disincentive and encourage APS to support additional increases in energy efficiency through programs and other initiatives such as support of building energy codes?

A. Yes. The financial interest of APS should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings and larger reductions in customer energy bills.

SWEEP supports decoupling mechanisms to address issues related to energy efficiency, i.e., when such mechanisms would be effective in substantially increasing customer energy efficiency and reducing the financial disincentive to electric utility support of increased energy efficiency.

SWEEP is not in favor of decoupling solely or primarily as a mechanism for the utility to recover its fixed costs. Therefore, in SWEEP's view the implementation of decoupling is premised on substantial increases in customer energy efficiency, for which the decoupling mechanism would reduce the financial disincentive to the utility of such increased energy efficiency. Because the EEES will deliver substantial energy efficiency savings for APS customers, decoupling in this situation is justified.

Q. Does full decoupling completely and effectively reduce Company disincentives for the support of activities that eliminate energy waste, including activities not directly linked to the Company's energy efficiency programs?

A. Yes. Full decoupling completely and effectively reduces Company disincentives for the support of activities that eliminate energy waste. As such, full decoupling is important not only for full utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs. This could include utility support for building energy codes; appliance standards; energy education and marketing; state and local government energy conservation efforts; and federal energy policies.

Q. Does SWEEP support the decoupling mechanism (Efficiency and Infrastructure Account or "EIA") proposed by APS?

A. SWEEP supports the revenue per customer decoupling mechanism proposed by APS with two exceptions:

1. SWEEP supports a true 3% cap on upward decoupling adjustments that would apply for each and every adjustment period and for which any carried-forward deferred balance would be subject. SWEEP does not support the cap proposed by the Company, which would limit the *amount of increase* in the decoupling adjustment from one year to the next to 3% of company's revenues but apparently would not apply (in the Company's EIA proposal) to the deferred balance. It appears that the Company's proposal could result in a decoupling adjustment of greater than 3% (e.g., in the event that the amount of the increase in the adjustment from one year to the next was 3% and there was a deferred balance from prior years, thereby leading to the sum of the two to be greater than 3%). The Company's proposed cap therefore would not represent a total and true cap of 3% of total company revenues per adjustment period as recommended by SWEEP and as discussed during the decoupling workshops.

2. In order to provide ratepayers with weather-related relief following extreme events, SWEEP would prefer more timely and current adjustments than the annual decoupling adjustments proposed by APS. During the technical conferences, APS explained that limitations to their billing system preclude more timely adjustments. SWEEP therefore recommends that the Commission order that any revision to or introduction of a new Company billing system incorporate capabilities that would enable more current decoupling adjustments (i.e., monthly adjustments to address weather and extreme weather events).

Q. Is the Company-proposed decoupling mechanism consistent with the Commission's Decoupling Policy Statement?

A. Yes. Together, the Company's energy efficiency portfolio – designed to meet the cumulative annual energy savings required by the EEES – and its proposed revenue per customer decoupling mechanism are consistent with the Commission's Decoupling Policy Statement. The Company's proposal meets the following policies set forth in the Policy Statement:

- "Utilities should pursue all cost-effective energy efficiency and demand side management resources, and should meet Arizona's Electric. . . Efficiency Standard of at least 22% electric energy savings by 2020."
- "Revenue decoupling may offer significant advantages over alternative mechanisms for addressing utility financial disincentives to energy efficiency."
- "While other decoupling models are appropriate in general, non-fuel revenue per customer decoupling may be well suited for Arizona."
- "Adoption of decoupling. . . should not occur as a pilot as this insufficiently supports demand-side management efforts, discourages beneficial changes in rate design, and is unlikely to encourage financial ratings improvements."
- "Full decoupling is preferable to partial decoupling."
- "Decoupling adjustments should occur at least on an annual basis, however, parties may propose more current adjustments as this may provide ratepayers with weather related relief following extreme events."
- "Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes."
- "Collars or caps on decoupling adjustments should be designed to encourage gradualism, and to minimize the short-term effects on customers."

Accounting for Commission-Adopted Policies as an Adjustment to Sales

Q. Does SWEEP recommend other improvements to ratemaking practices applied in this rate case proceeding?

A. Yes. The impacts of Commission-adopted policies, including the energy savings required by the EEES, should be reflected and accounted for in the test year sales used to set rates in this proceeding. Specifically, a pro-forma adjustment to sales (which would impact revenues) should be applied to test year sales, to account for the energy savings and load-reducing effects of the Commission-adopted EEES requirements. The EEES requirements and their impacts on sales are known and measurable. Further, applying the pro forma adjustment would result in better and more accurate alignment of revenues and expenses based on these known and measurable quantities. If the Commission is concerned whether a full 100% of the EEES requirement would be met in each and every future year, the pro forma adjustment could be applied at a level of 75% of the EEES requirement.

Customer Bill Redesign and Disclosure

Q. Does SWEEP support a redesign of the APS bill?

A. SWEEP supports redesigning the APS bill in order to lessen customer confusion and provide customers with more useful information.

SWEEP would support either of the following:

1. If APS plans to simplify the bill by presenting fewer cost categories, SWEEP notes that recovering the vast majority of energy efficiency through base rates would be consistent with this intent. SWEEP also recommends that the DSM adjustor not be specifically identified on the customer bill, as not including the DSM adjustor on the bill would be consistent with the treatment of other energy resources, whose costs are not expressly identified by the current bill format.

OR

2. If APS plans to make the bill more transparent, SWEEP supports **full** disclosure **on the customer bill** of each and every energy resource, so that no one energy resource is singled out or ghettoized. For example, SWEEP would support the inclusion of a graphic similar to the pie graph presented by APS witness Don Robinson that illustrates how each rate dollar is spent. If such a graphic were included, however, the costs associated with each and every energy resource would need to be clearly delineated.

Infrastructure Tracker

Q. Does SWEEP support the Company-proposed infrastructure tracker (Environmental and Reliability Account or "ERA")?

A. No. SWEEP does not support the ERA and urges the Commission to disapprove the Company-proposed infrastructure tracker. The ERA is too broad and too far reaching. The future costs that the ERA is proposed to address and recover should not be addressed in an infrastructure tracker.

Conclusion

Q. Does this conclude your testimony?

A. Yes.

SWEEP Rate Design

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
SWEEP-2

<u>COMMISSIONERS</u>

GARY PIERCE, CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-11-0224

Rate Design Direct Testimony of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

December 2, 2011

Rate Design Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-11-0224

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have you filed direct testimony in this docket previously?

A. Yes. I filed direct testimony on behalf of SWEEP on November 18, 2011.

Q. What is the purpose of your rate design direct testimony?

A. In my rate design testimony, I will address four issues:

1. Which customer rate classes should be excluded from full decoupling or lost revenue recovery mechanisms;
2. Increasing the basic service charge is not in the interest of customers;
3. Other DSM energy efficiency funding and cost-recovery mechanisms; and
4. Providing customers with useful information about utility costs and resources.

Which Customer Rate Classes Should be Excluded from Full Decoupling or Lost Revenue Recovery Mechanisms?

Q. Did the Commission's Decoupling Policy Statement address the degree and nature of customer class participation in full decoupling or lost revenue recovery mechanisms?

A. Yes. The Commission's Decoupling Policy Statement stated: "Broad participation in decoupling is preferred; however, the unique characteristics of each utility may merit different treatment of some customer classes." During the Commission's decoupling workshops, SWEEP supported the broad participation of all or the vast majority of customer classes. SWEEP also expressed its willingness to consider excluding the largest customers from the mechanisms if it was demonstrated that the customers do not contribute to the recovery of fixed costs.

Q. Are there APS customers or classes of customers that should be excluded from full decoupling or lost revenue recovery mechanisms?

A. Yes. SWEEP supports the exclusion of only the largest customers (or the rate classes that include only the largest customers) from full decoupling or lost revenue recovery mechanisms if it is demonstrated that the customers do not contribute to the recovery of fixed costs. In this rate case, SWEEP is open to considering the exclusion of certain customers (such as E-34 or E-35 customers). However, any such exclusion should be based on evidence that the customers or customer rate classes do not contribute to the recovery of fixed costs.

Increasing the Basic Service Charge is Not in the Interest of Customers

Q. Is increasing the basic service charge, as an alternative to full decoupling or lost revenue recovery mechanisms, in the interest of customers?

A. No. SWEEP does not support increasing the basic service charge as a mechanism to recover additional fixed costs. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or increase their energy efficiency. Higher basic service charges are not in the public interest and are not in the interest of customers.

Other DSM Energy Efficiency Funding and Cost-Recovery Mechanisms

Q. Are there DSM energy efficiency program funding and cost-recovery mechanisms that would reduce the rate impacts of the DSM energy efficiency program funding increases?

A. Yes. The Commission could choose to amortize or capitalize a portion of the DSM energy efficiency expenditures, similar to how investments in power plants are recovered through customer rates over time, thereby reducing the customer rate impacts of the programs in the early years of the Energy Efficiency Standard (EES). For example, the Commission could spread the additional DSM costs to ratepayers across several years (e.g., 5 years) in a manner that acknowledges that the energy efficiency benefits are achieved and experienced by customers over several years.

Q. Could a combination of DSM funding and cost-recovery mechanisms be used?

A. Yes. For example, the APS DSM energy efficiency program funding could consist of a significant portion of the funding in base rates (as stated in my direct testimony), a portion recovered through the DSM adjustment mechanism, and a portion capitalized or amortized over five years or more.

Providing Customers with Useful Information about Utility Costs and Resources

Q. What objectives should be considered when redesigning the customer bill and providing useful information to customers?

A. As I testified in my direct testimony, customers should be provided with useful information on utility costs and resources so that customers can fully understand how their money is being allocated and spent, and on which resources and costs. The customer bill itself should be simplified so that information is readily accessible and easy to understand for customers. There are two objectives here: providing a simple bill to customers, and providing useful and transparent information to customers.

Q. How can these two seemingly contradictory objectives be achieved without burdening or confusing customers?

A. These two crucial objectives – transparency and simplicity – could be achieved without burdening customers by:

1. Simplifying the regular bill by presenting fewer cost categories and treating all energy resources equally in terms of disclosure (for example, not including the DSM adjustor as a line item on the bill, which would be consistent with the treatment of other energy resources, whose costs are not expressly identified by the current bill format).

AND

2. Providing supplemental information on utility costs and energy resources to customers at all times via the web and quarterly or annually via a bill insert, email, and/or other communication – and not on the customer bill itself. This information would include a graphic similar to the pie graph presented by APS witness Don Robinson that illustrates how each rate dollar is spent. If such a graphic were included, however, the costs associated with each and every energy resource would also need to be clearly delineated. In addition, all regular bills

sent to customers would direct customers to the location on the web where utility and energy resource costs, as well as the energy resource mix, would reside, with a phone number customers could call for specific details.

Conclusion

Q. Does this conclude your rate design testimony?

A. Yes.

SWEEP Partial Opp.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
SWEEP - 3

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-11-0224

Testimony in Partial Opposition to the Proposed Settlement Agreement of

Jeff Schlegel

Southwest Energy Efficiency Project (SWEEP)

January 18, 2012

Testimony in Partial Opposition to the Proposed Settlement Agreement of Jeff Schlegel, SWEEP

Docket No. E-01345A-11-0224

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Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. Did you submit direct testimony in this proceeding?

A. Yes. I filed direct testimony and direct rate design testimony on behalf of the Southwest Energy Efficiency Project (SWEEP).

Q. Have there been any changes in your qualifications or representation of SWEEP?

A. No.

Summary of SWEEP's Testimony in Partial Opposition to the Proposed Settlement

Q. What is the purpose of your testimony?

A. In my testimony, I will:

- Summarize how the proposed Settlement Agreement limits the Commission from fully exploring the policy options for addressing utility financial disincentives to energy efficiency, including limiting the Commission's consideration of full revenue decoupling;
- Describe why full revenue decoupling, a mechanism the Commission adopted one month ago in the Southwest Gas rate case after a thorough evaluation of all of the evidence, is a superior option for the treatment of utility financial disincentives to energy efficiency compared to the lost fixed cost revenue recovery mechanism proposed in the Settlement Agreement;
- Recommend that the Commission substitute full revenue decoupling in place of the lost fixed cost revenue recovery mechanism proposed in the Settlement Agreement because full revenue decoupling more completely and effectively reduces utility company disincentives for the support of activities that eliminate energy waste, while lost fixed cost revenue recovery does not;
- Express why rate case moratoriums can limit the Commission's ability to direct energy policy, and emphasize why caution should be exercised when enacting a rate case moratorium, especially one as long as four years;
- Explain that performance incentives are an important policy instrument that the Commission should exercise to influence and direct energy efficiency outcomes during the energy efficiency implementation plan process;
- Provide recommendations on objectives and design criteria for an energy efficiency performance incentive that establishes a clear connection between the

performance incentive level and the achievement of cost-effective energy savings.
- Describe why and how energy efficiency, as a fundamental resource meeting the real energy needs of customers at lowest cost, should be adequately funded in base rates at stable levels; and
- Explain how and why the impacts of Commission-adopted policies should be reflected and accounted for in adjustments to test year sales used to set rates.

Utility Financial Disincentives to Energy Efficiency and Preserving the Commission's Ability to Consider Options and Decide Energy Policy

Q. How does the proposed Settlement Agreement offer to address utility financial disincentives to energy efficiency?

A. The Settlement Agreement proposes to implement a lost fixed cost revenue (LFCR) recovery mechanism. This mechanism would recover a portion of the distribution and transmission costs associated with the pursuit of energy efficiency and distributed generation by residential, commercial, and industrial customers. The Settlement Agreement would also allow residential customers to "opt out" of this LFCR mechanism by accepting higher fixed charges through an increased basic service charge.

Q. Does the proposed Settlement Agreement limit the Commission from fully considering the policy options for addressing utility financial disincentives to energy efficiency?

A. Yes. By offering only one option for addressing utility financial disincentives to energy efficiency (i.e., the LFCR mechanism), the proposed Settlement Agreement limits the Commission from fully exploring and vetting the various policy options it could consider, including full revenue decoupling.

In contrast, the proposed Settlement Agreement offered in the Southwest Gas rate case (and adopted by the Commission in December 2011), gave the Commission a choice: it presented two clear policy options for Commission consideration – a LFCR mechanism and a full revenue decoupling mechanism. As such, the Southwest Gas Settlement Agreement provided a framework for the Commission to thoroughly vet the policy and legal issues surrounding both full revenue decoupling and lost fixed cost revenue recovery and to make a decision after a thorough deliberation of all of the evidence.

Q. Does the Settlement Agreement address, in a positive and responsive manner, the concerns raised by Commissioners during the Special Open Meeting on December 16, 2011, about settlement agreements limiting the Commission's ability to consider a full range of options and decide energy policy?

A. No. As discussed above, the proposed Agreement does not offer a framework for the Commission to thoroughly vet the policy and legal issues surrounding both lost fixed cost revenue recovery and full revenue decoupling. Indeed, in any adoption of the full Settlement as filed, the Commission would not be able to consider full revenue decoupling at all. Instead, it would have to consider this option *entirely outside* of the Agreement. Accordingly, the proposed Settlement limits the Commission's ability to direct energy policy related to the treatment of utility financial disincentives to energy efficiency and is therefore not responsive to the stated concerns by Commissioners at the December meeting. Most notably, the proposed Settlement excludes from Commission consideration full revenue decoupling — the very option that the Commission approved for the Southwest Gas Company one month ago after a thorough evaluation of evidence on both lost fixed cost revenue recovery and full revenue decoupling.

Q. Why is full revenue decoupling a policy option worthy of Commission consideration?

A. As I testified in my direct testimony, the financial interest of the Arizona Public Service Company ("Company" or "APS") should be better aligned with the interests of its customers by reducing financial disincentives to utility support of energy efficiency, thereby resulting in more energy savings, total lower costs for customers, and larger customer energy bill reductions.

Full revenue decoupling completely and effectively reduces utility company disincentives for the support of activities that eliminate energy waste. As such, full revenue decoupling is important not only for full, enthusiastic utility support of energy efficiency programs but also for activities that reduce sales but are not or may not be directly linked to the Company's portfolio of energy efficiency programs. This could include utility support for building energy codes; appliance standards; energy education and marketing; state and local government energy conservation efforts; and federal energy policies.

Q. Why is full revenue decoupling a superior option for the treatment of utility financial disincentives to energy efficiency than the proposed LFCR mechanism?

The proposed LFCR mechanism inadequately reduces utility disincentives to energy efficiency, and therefore results in fewer opportunities for customers to reduce their energy bills. Consequently, it discourages Company support of building energy codes, appliance efficiency standards, and state initiatives and legislation. It will also likely result in contentious and protracted technical proceedings at the Commission (as has been the experience in lost revenue recovery mechanism proceedings in other states). Finally, the LFCR mechanism represents an automatic rate increase. In contrast, because full revenue decoupling allows for rate adjustments in both a positive and negative direction, decoupling could result in either a credit or a charge on the customer bill.

LFCR does nothing to reduce APS' financial incentive to encourage customers to use more electricity – and the more customers waste energy, the more APS revenues and earnings increase. Also, under LFCR in the Agreement, as the Arizona economy recovers and electric demand increases, APS revenues and earnings would also increase. Specifically, APS could retain all revenues higher than the revenue levels established by the Agreement, which would result in higher earnings. APS would also retain all revenues higher than the revenue levels established by the Agreement from increased electrification and electric vehicles. In contrast, full decoupling would provide a credit to customers for any revenues higher than authorized revenues (determined as authorized revenue per customer multiplied by the number of customers).

Q. Does the proposed residential opt-out rate serve the interest of customers who want to reduce their energy bills?

A. No. The residential opt-out rate requires customers to accept higher fixed charges through an increased basic service charge. As I testified in my rate design direct testimony, SWEEP does not support increasing the basic service charge as a mechanism to recover additional fixed costs. Increasing the basic service charge mutes the price signal to customers by reducing the amount of utility bill cost savings that customers experience when they conserve energy or increase their energy efficiency.

Q. What action should the Commission take on the Settlement Agreement?

A. The Commission should approve the Settlement Agreement with the exception of Section IX (see additional comments of other portions of Section IX, below). In its stead, the Commission should substitute the Company's original decoupling proposal.

<u>Rate Case Moratorium/Stay-Out Provision and Preserving the Commission's Ability to Decide Energy Policy and Respond to Changing Conditions</u>

Q. Does the Settlement Agreement propose a rate case moratorium?

A. Yes. The proposed Settlement Agreement includes a four-year rate case stay-out provision that, if adopted, would prohibit the Company from filing a new general rate case application until July 1, 2016.

Q. Do rate case moratoriums limit the Commission's ability to direct and determine energy policy?

A. Rate case moratoriums effectively freeze rates for a specified period of time, despite shifts in the economy or energy/regulatory policies that might otherwise call for a reexamination of and possible change to rates. In turn, rate case moratoriums can limit the Commission's ability to direct energy policy, especially those policies that come about or evolve after establishment of the moratorium in question.

Q. Are there any recent examples to illustrate this point?

Yes. The Settlement Agreement adopted in Tucson Electric Power Company's (TEP) 2008 rate case included a stay-out provision that prohibits the Company from filing a new general rate case application until mid-2012. As the Commission is fully aware, this stay-out provision has constrained Commission options and actions related to the achievement of the Electric Energy Efficiency Standard (adopted in 2010) and the Commission's review of the TEP EE Implementation Plan, and may prevent or limit TEP customers from receiving the full value of energy efficiency investments (i.e., reducing their utility bills and lowering total costs for customers).

Q. Are rate case moratoriums a good idea during uncertain economic times?

A. During uncertain economic times, a rate case moratorium may offer stability to customers in the form of a rate freeze. Alternatively, it may subject customers to higher than necessary rates and costs or to higher future costs. And, when combined with the LFCR mechanism in the Agreement (rather than full decoupling), it results in APS retaining all of the revenues that are higher than the revenue levels established by the Agreement rather than providing credits to customers, for the full period of the stay-out provision. For these reasons, SWEEP believes the Commission should exercise caution when enacting a moratorium, especially one as long as four years (as proposed in this Settlement Agreement).

Q. What action should the Commission take to mitigate the negative effects of the long stay-out provision?

A. If the Commission chooses to adopt the proposed Agreement, SWEEP recommends shortening the stay-out period to three years. At the very least, SWEEP recommends that in three years time or sooner the Commission exercise its authority to initiate a systematic review to determine if rates are just and reasonable for customers and to determine whether the continuation of the stay-out provision is warranted.

Energy Efficiency Performance Incentive

Q. What does the Settlement propose for an energy efficiency performance incentive?

A. If adopted, the Settlement Agreement would slightly modify the Company's current performance incentive by removing and changing certain performance tiers. It would also initiate a stakeholder process for the development of a new performance incentive by December 31, 2012, for Commission consideration and possible implementation at a later date.[1]

[1] See Sections 9.14b and 9.14d of the proposed Settlement Agreement.

Q. Does the Electric Energy Efficiency Standard provide guidance for when a performance incentive may be adopted?

A. Yes. The Electric Energy Efficiency Standard states that, "In the implementation plans required by R14-2-2405, an affected utility may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in R14-2-2404. The Commission may also consider performance incentives in a general rate case" (R14-2-2411). In other words, the Electric Energy Efficiency Standard allows for performance incentives to be proposed and adopted during a rate case or during the annual energy efficiency implementation plan process.

Q. Does SWEEP have a preference on when performance incentives should be proposed and adopted?

A. Yes. SWEEP views performance incentives as an important policy instrument that the Commission should exercise to influence and direct energy efficiency programs and outcomes for the benefit of customers. To that end, we believe it is critical for the Commission to be able to oversee and modify performance incentive design during the energy efficiency implementation plan process, when new energy efficiency programs and initiatives are proposed, reviewed, and approved by the Commission, and when energy efficiency policy is implemented.

Q. What is your view of the timing of the process for the development of a new performance incentive, as set forth in the Settlement Agreement Section 9.14d?

A. Consistent with the arguments above, SWEEP believes the new performance incentive should be developed by mid-2012, filed by APS as part of its 2013 Demand Side Management (DSM) Implementation Plan, and considered by the Commission as part of its review of the 2013 DSM Implementation Plan. There is no reason for APS, Staff, and stakeholders to wait until December 2012 to complete the development of a new performance incentive that will better incent achievement of cost-effective energy savings.

Q. But mid-2012 is likely earlier timing than a final decision in this proceeding, correct?

A. Yes. For this reason SWEEP recommends that APS initiate a process now to work with Staff and other stakeholders to develop a new performance incentive for Commission consideration as part of the 2013 DSM Implementation Plan process.

Q. Does SWEEP have any recommendations with respect to the performance incentive, if the Commission were to adopt the proposed Settlement Agreement with the performance incentive process and timing as set forth in the Settlement Agreement?

A. Yes. If the Commission adopts the proposed Settlement Agreement, thereby delaying the consideration of a new performance incentive until December 2012 at the earliest, the Commission should make known its objectives for performance incentive design, and these objectives should be set forth in the Commission's final decision. In SWEEP's view an appropriately designed performance incentive would meet the following objectives:

1. It encourages the Company to pursue cost-effective energy efficiency;

2. It is designed in such a way to avoid any perverse incentives;

3. It is based on clearly-defined goals and activities that are sufficiently monitored, quantified, and verified;

4. It is available only for activities for which the Company plays a distinct and clear role in bringing about the desired outcome; and

5. It is kept as low as possible while balancing and meeting the objectives and principles mentioned above.

Q. Does SWEEP have any additional recommendations on specific design criteria for the performance incentive, which the Commission should require in its final decision?

A. Yes. If the Commission adopts the proposed Settlement Agreement with the process to develop a new performance incentive, the Commission should also require the following design criteria for the new performance incentive:

- Encourage the achievement of energy savings and net benefits for customers through a performance incentive with an eligible incentive level equivalent to 7% of net benefits on a pre-tax basis;

- Include new components and metrics that emphasize increased comprehensiveness of energy efficiency program services provided to customers and result in higher percent savings, encourage cost-efficiency in the use of ratepayer funds (i.e., total net benefits to customers per dollar of ratepayer funding provided), and target the achievement of specific performance goals such as serving a targeted number of low income customers and/or issuing a specific targeted number of residential loans or a targeted total loan amount; and,

- Have an absolute dollar cap on the total incentive amount that the Company may earn, set at 115% of the eligible incentive level (determined at 100% of target performance), thereby not incenting increased program spending through the design of the performance incentive mechanism or its incentive cap.

Adequate Funding and Stability for Energy Efficiency

Q. Does the proposed Settlement Agreement adequately support energy efficiency?

A. No. The proposed Settlement Agreement, except for a general statement in support of energy efficiency[2], does not include provisions to adequately fund or support energy efficiency. For example, it does not support the level of savings set forth in the Electric Energy Efficiency Standard (there is no explicit support for the energy savings levels in the Energy Efficiency Standard or for any other level of savings for customers) and does not provide adequate or stable funding. Also, the Agreement does not fund a majority of energy efficiency costs in base rates. This is in contrast to other energy resources, which are afforded stability through funding in base rates.

Q. How can adequate funding for energy efficiency be ensured?

A. In order to provide adequate treatment for this central and least cost resource, total funding of $70 million for energy efficiency should be expensed in base rates, while commensurately reducing the Demand Side Management (DSM) adjustor.[3] Since $10 million of energy efficiency funding is already expensed in base rates, a $60 million increase would be necessitated. The DSM adjustment mechanism should still remain intact, but should recover or refund any energy efficiency funding amounts above or below $70 million, as needed to implement and deliver energy efficiency offerings to customers. In this way, the DSM adjustment mechanism would serve as a flexible means of recovering additional energy efficiency funding (as needed). For example, based upon the Commission Staff's Second Revised Report and Recommended Order on APS' 2012 DSM Implementation Plan, SWEEP estimates that expensing $70 million of energy efficiency program costs in base rates would reduce the total amount collected through the 2012 DSM adjustor for 2012 energy efficiency programs (not including demand response costs) from $71.4 million[4] to $1.4 million, reducing the DSM adjustor for 2012 energy efficiency programs from about $0.0022 per kWh[5] to $0.000052 per kWh.

Q. Why should energy efficiency be adequately funded in base rates at stable levels?

A. Energy efficiency is a fundamental resource meeting the real energy needs of customers at lowest cost. Additionally, it is a positioned to become the Company's

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[2] Section 9.1 of the proposed Settlement Agreement states, "The Signatories support energy efficiency as a low cost energy resource."

[3] As I testified in my direct testimony, in its 2012 DSM Implementation Plan, the Company proposed to spend $78 million, while delivering $194 million in net benefits to customers. Hence, expensing $70 million in base rates would equate to approximately 90% of these anticipated funds.

[4] The $71.4 million amount includes the cost of 2012 energy efficiency programs; the cost of the proposed Codes and Standards program; measurement, evaluation, and research; and the energy efficiency performance incentive.

[5] This value accounts for the $10 million in energy efficiency funds already expensed in base rates.

primary resource to meet energy growth over the next decade. In fact, from 2011 to 2020, energy efficiency will meet more than half of APS' planned energy growth, making it the Company's largest growing energy resource for meeting load growth over the next ten years. For these reasons, energy efficiency must be satisfactorily funded and provided funding stability – else the numerous public interest benefits of this core resource may not be realized. Stability in policies and funding is a key to maximizing the customer benefits from energy efficiency.

Accounting for Commission-Adopted Policies as an Adjustment to Sales

Q. Are there other rate-making issues in this case that the Commission should consider, as part of a package of improved practices in utility regulation and ratemaking in an era of focusing on reducing customer energy bills through increased energy efficiency?

A. Yes. The current system for ratemaking does not fully account for Commission-adopted policies. In particular, it does not account at all for the Electric Energy Efficiency Standard or its impacts. Indeed, the test year sales based on an historic test year and used to set rates in this proceeding ignore the energy savings required by the Standard that will be experienced in the years for which the new rates are effective.

Q. Why is it important to account for Commission-adopted policies when setting rates?

A. If the rate setting process does not account for Commission-adopted policies, a disconnect arises between ratemaking and the very policies themselves. This disconnect can lead to regulatory lag, mismatches between cost causation and cost recovery, and the under-recovery of authorized fixed costs. The Commission should approve rates that are adequate in recovering Commission-authorized costs within the same time period in a manner that is consistent with the effects of Commission-adopted policies.

Q. How can the Commission remedy this issue?

A. The impacts of Commission-adopted policies should be reflected and accounted for in the test year sales used to set rates. As I testified in my direct rate design testimony, a post-test year adjustment to sales (which would impact revenues) should be applied to test year sales, to account for the energy savings and load-reducing effects of the Commission-adopted Electric Energy Efficiency Standard requirements. The Electric Energy Efficiency Standard requirements and their impacts on sales are known and measurable. Further, applying the post-test year adjustment would result in better and more accurate alignment of revenues and expenses based on these known and measurable quantities. If the Commission is concerned whether a full 100% of the Electric Energy Efficiency Standard requirement would be met in each and every year, the post-test year adjustment could be applied at a level of 75% of the Electric Energy Efficiency Standard requirement.

Conclusion

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT S-1

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BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11-0224

PUBLIC

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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ATTACHMENTS

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

The purpose of my testimony is to address the application for a general rate increase filed by APS. Specifically, I will be addressing the revenue requirement, rate base, net operating income, and selected other issues, including APS' proposal for new depreciation rates. I also discuss a potential cost recovery mechanism for the Commission's consideration to address Four Corners related cost changes.

APS' has requested a total base rate revenue increase of $95.493 million, which includes an increase of $54.610 million on original cost rate base and $40.883 million for additional revenue on the fair value increment. In an update filed by APS on October 26, 2011, APS has revised its base rate revenue increase request to $84.909 million, consisting of $42.646 million on original cost rate base and $42.263 million for the fair value increment.

On original cost rate base, including post-test year plant additions through March 31, 2012 and the rate of return recommended by Staff witness David Parcell, I have calculated a revenue sufficiency for APS of approximately $48.932 million. Staff is presenting the Commission with two alternatives for the revenue requirement change on fair value rate base ("FVRB") using the fair value rate of return ("FVROR") recommended by Staff witness Parcell. Under alternative 1, APS has a revenue sufficiency of approximately $48.932 million. Under FVROR alternative 2, the base rate revenue sufficiency is approximately $7.449 million. These amounts compare directly to the amounts in APS' filing on APS Schedule A-1. Staff is recommending the use of alternative 2 in this case, which results in a jurisdictional base rate decrease of approximately $7.449 million.

I recommend the following adjustments to the original cost and fair value rate base proposed by APS:

Summary of Staff Adjustments to Rate Base		Original Cost	Fair Value
Adj		Increase	Increase
No	Description	(Decrease)	(Decrease)
B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	$ (35,406)	$ (35,406)
B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	$ (23,458)	$ (23,458)
B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	$ (17,536)	$ (17,536)
B-4	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	$ (53,196)	$ (53,196)
B-5	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	$ 60,124	$ 60,124
B-6	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	$ 1,726	$ 1,726
B-7	Cash Working Capital	$ 10,467	$ 10,467
	Total of Staff Adjustments	$ (57,279)	$ (57,279)
	APS Proposed Rate Base	$ 5,720,277	$ 8,224,405
	Staff Proposed Rate Base	$ 5,662,998	$ 8,167,126

Each of these adjustments is discussed in my testimony.

Staff's adjusted rate base and how it compares with APS' is summarized below:

$000's	APS	Staff	Difference
Summary of Rate Base	Schedule B-1	Schedule B	
Original Cost Rate Base	$ 5,720,277	$ 5,662,998	$ (57,279)
RCND Rate Base	$ 10,728,532	$ 10,671,253	$ (57,279)
Fair Value Rate Base	$ 8,224,405	$ 8,167,126	$ (57,279)

The adjusted fair value rate base has been used by Staff to compute the required base rate revenue requirement.

I also recommend several adjustments to net operating income. A summary Staff's adjustments and a reconciliation of the revenue deficiency on original cost rate base is presented in the following table:

Adj. No.	Description	Pre-Tax Revenue or Expense Adjustment	Net Operating Income Increase (Decrease)
C-1	Forensic Investigation of Grant-Funded Projects	$ (2,057)	$ 1,244
C-2	General Advertising Expense	$ (572)	$ 346
C-3	Property Tax Expense	$ (584)	$ 353
C-4	Solar Post Test Year Plant Depreciation and Property Tax Expense	$ (1,301)	$ 787
C-5	Fossil Post Test Year Plant Depreciation and Property Tax Expense	$ (783)	$ 473
C-6	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	$ (363)	$ 220
C-7	Distribution and General and Intangible Post Test Year Plant Depreciation and Property	$ (2,664)	$ 1,611
C-8	Interest Synchronization	$ -	$ (638)
C-9	Base Fuel and Purchased Power	$ (9,575)	$ 5,792
C-10	Payroll Expense Adjustment - New Union Contract	$ 4,994	$ (3,021)
C-11	Depreciation Expense - New Depreciation Rates	$ (4,735)	$ 2,864
C-12	Prospective Amortization of 2010 Severance Costs	$ (3,128)	$ 1,892
C-13	Directors and Officers' Liability Insurance Expense	$ (550)	$ 333
C-14	Incentive Compensation	$ (18,930)	$ 11,451
C-15	Normalized Fossil Non-Plant Maintenance Expense	$ (266)	$ 161
C-16	Edison Electric Institute Dues	$ (216)	$ 131
Total of Staff's Adjustments		$ (40,730)	$ 23,999
	Adjusted Net Operating Income per APS		$ 474,356
	Adjusted Net Operating Income per Staff		$ 498,355

My testimony addresses the Company's proposed depreciation rates. The new depreciation rates proposed by APS are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibit, Attachment REW-2 entitled "2011 Depreciation Rate Study" which was prepared by Dr. White's firm, Foster Associates, Inc. The Company's proposed rates were developed using a depreciation system composed of the straight-line method, vintage group procedure and remaining life technique. APS has developed its proposed depreciation rates for production facilities by unit and by type of plant in service at each unit.

Based on December 31, 2010 plant investment, the new depreciation rates proposed by APS decrease depreciation expense by $41.301 million (from $305.37 million at present rates to $264.07 million at APS' proposed rates).[1] Of the 170 plant accounts studied, APS proposes depreciation rate reductions for 97 accounts and increases for 73 accounts. On a composite

[1] Approximately $24.630 million of this reduction relates to the prospective cessation of depreciation on Four Corners Units 1-3, as shown on APS' Attachment REW-2, Statement B, page 26.

basis, the Company's proposed new rates for APS plant produce a decrease of 0.37 percentage points, from the current composite rate of 2.77 percent to a composite at new rates of 2.40 percent.

With the exception of the meters account[2], the depreciation rates proposed by APS are generally appropriate and have been determined using depreciation methods consistent with how depreciation rates have been determined for APS in prior cases.

APS has appropriately incorporated the operating license extension into its development of new depreciation rates for the Palo Verde Nuclear Generating Station.

APS has also incorporated proposed changes to depreciation rates for the Four Corners steam generating station related to the acquisition by APS of Southern California Edison's ("SCE") share in Four Corners Units 4 and 5 and to APS' expectations for the operation of that plant and in view of environmental regulations. APS' proposal to acquire SCE's share of Four Corners Units 4 and 5 is currently pending before the Commission in Docket No. E-01345A-10-0474. APS' incorporation of the depreciable life changes for the Four Corners plant also incorporates a related assumption that Units 1-3 will be retired in 2012, thus APS' proposed annualized depreciation accrual for Four Corners Units 1-3 decreases from approximately $24.630 million at current depreciation rates to zero at APS' proposed depreciation rates.[3]

With respect to meters, APS' proposal to reduce the average service lives from 26 years (upon which the currently authorized depreciation rates for meters are based) to 15 years should be rejected. In APS' last rate case, the Company represented that: "The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology."[4] That APS recommendation should continue to apply in the current case. The currently authorized depreciation rates for meters using a 26 year anticipated life are also in line with depreciation rates for meters that have been authorized for other Arizona utilities. The existing authorized rates for meters should continue to be applied. The issue of service lives for meters should be re-examined in APS' next rate case.

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[2] APS records its meters investment in sub-account 370.01 for electronic meters and 370.03 for AMI meters.
[3] See, e.g., APS' Exhibit REW-2, at page 28.
[4] See, e.g., Attachment REW-1 to APS witness Dr. White's direct testimony in Docket No. E-01345A-08-0172, at page 4.

INTRODUCTION

A. Background and Qualifications

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July, 1979. Before becoming involved in utility regulation where the majority of my time for the past 31 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission ("ACC" or "Commission")?

A. Yes. I have previously testified before the Commission on a number of occasions. I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS" or "Company"), and APS' Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827, and E-01345A-08-0172 concerning proceedings involving APS base rates and other matters. I testified before the Commission in the Arizona-American Water Company in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343. I also testified before the Commission in the last UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the last UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as the Southwest Gas Corporation rate cases, G-01551A-07-0504 and G-01551A-10-0458.

B. Purpose of Testimony

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Commission's Utilities Division ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the application for a general rate increase filed by APS. Specifically, I will be addressing the revenue requirement, rate base, net operating income, and selected other issues, including APS' proposal for new depreciation rates. I also discuss a potential cost recovery mechanism for the Commission's consideration to address Four Corners related cost changes.

Q. Please briefly describe the information you reviewed in preparation for your testimony.

A. The information I reviewed included APS' application and testimony, APS' responses to data requests of Staff and other parties, information provided to me by Staff, and other publicly available information.

C. Content of Attachments to Testimony

Q. Have you attached any exhibits to be filed with your testimony?

A. Yes, I have five attachments, Attachments RCS-1 through RCS-5.

Q. What is shown in each of those attachments?

A. Attachment RCS-1 presents by educational background and qualifications.

Attachment RCS-2 presents the results of my analysis including Staff's recommended revenue requirement, rate base and adjusted net operating income.

Attachment RCS-3 presents copies of non-confidential responses to data requests and selected non-confidential documents that are referenced in my testimony.

Attachment RCS-4 presents copies of selected APS confidential responses to discovery and other confidential documents that are referenced in my testimony.

Attachment RCS-5 presents excerpts of regulatory commission orders addressing ratepayer/shareholder sharing of Directors and Officers Liability Insurance Expense.

D. General Background to APS' Rate Request

Q. Please briefly provide some background for the request that APS has made in the current proceeding.

A. APS is an Arizona utility providing electricity to more than 1 million customers in 11 of Arizona's 15 counties. With its headquarters in Phoenix, APS is the largest subsidiary of Pinnacle West Capital Corporation ("PWCC" or "PNW"[5]). APS is the largest electric utility in Arizona.

APS' current base rates became effective January 1, 2010 pursuant to Decision No. 71448 dated December 30, 2009. That case, Docket No. E-01345A-08-0172 used a test year ending December 31, 2007.

On June 1, 2011, APS filed with the Commission an application for a base rate increase of $95.5 million, using a test year ending December 31, 2010.

[5] PNW is the stock symbol for Pinnacle West Capital and rating agency and investment reports sometimes therefore use "PNW." In this testimony, both abbreviations, PWCC and PNW, are used interchangeably.

REVENUE REQUIREMENT

A. Summary of APS' Requested Increase

Q. Please briefly summarize APS' basis for its request for a rate increase.

A. Using a test year ending December 31, 2010, with pro forma adjustments, in its original filing, APS was seeking a base rate increase of $95 million. On October 26, 2011, APS filed certain updated information, which reduces the base rate increase APS is seeking to approximately $85 million. The Company's originally filed and updated base rate revenue increase request is summarized in the table below:

Summary of APS' As-Filed and Updated Base Rate Revenue Increase Request

Component (Millions of Dollars)	APS' Filed Base Rate Increase Request	APS' Updated Base Rate Increase Request
Non-Fuel Costs	$ 194	$ 196
AZ Sun Transfer	$ 45	$ 42
Fuel Costs	$ (144)	$ (153)
Base Rate Increase Request	**$ 95**	**$ 85**

B. Summary of Staff's Recommendation

Q. What revenue increase does Staff recommend?

A. Compared with APS' originally filed $95 million and revised $85 million base rate increases shown in the above table, Staff recommends a base rate revenue decrease of approximately $7.449 million on adjusted Fair Value rate base.

Q. What base cost of fuel is incorporated in Staff's recommendation?

A. APS' base cost of fuel has been reset to 3.2071 cents per kWh, based on APS' current forecast for 2012.[6] Staff and APS are both recommending in the current APS rate case that the 90/10 sharing provision of APS' existing Power Supply Adjustor ("PSA") be

[6] Staff's adjustment for the base cost of fuel and purchased power is presented on Attachment RCS-2, Schedule C-9.

eliminated.[7] This will help assure that the reductions in fuel and purchased power costs that APS may experience prospectively will be fully passed through to customers. APS estimates additional annual incremental fuel and purchased power cost savings of as much as $31.4 million if its proposed acquisition of Southern California Edison's ("SCE") share of Four Corners Units 4 and 5 is approved.[8]

Q. What calculations have you presented in support of that recommendation?

A. On Attachment RCS-2, Schedule A, page 1, I present a calculation of the revenue sufficiency for APS on original cost rate base ("OCRB"). As shown on Schedule A, page 1, column C, on OCRB my calculations show a jurisdictional base rate revenue sufficiency of $48.932 million. Column D presents a calculation on fair value rate base ("FVRB") similar to the one presented in APS' filing. Staff's recommended decrease of approximately $7.449 million represents a decrease from current base rate revenue from sales to ultimate customers of approximately 0.26 percent.

Staff is also presenting the Commission with two options for the Fair Value rate of return ("FVROR") for APS. On Schedule A, page 2, I present Staff's alternative calculations using adjusted FVRB. These calculations show FVRORs ranging from 5.74 percent to 6.05 percent. On adjusted FVRB under Staff's option 1, which uses a fair value rate of return of 5.74 percent, the base rate decrease is $48.932 million. Under option 2 the fair value rate of return for APS is 6.05 percent, and the jurisdictional base rate decrease is approximately $7.449 million.

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[7] Staff witness Michael McGarry is addressing PSA issues in the current APS rate case for Staff.

[8] See, e.g., Attachment RCS-2, Schedule C-9, column F, line 10. This additional fuel cost savings is not reflected in Staff's presentation at this time because the Commission has not yet issued a decision on whether or not to approve APS' proposed acquisition of SCE's share in Four Corners Units 4 and 5. That proposed acquisition is pending before the Commission in Docket No. E-01345A-10-0474.

Attachment RCS-2, Schedule D, shows the development of Staff's recommended fair value rate of return to be applied to FVRB. The testimony of Staff witness David Parcell also addresses the determination of the fair value rate of return.

C. Test Year

Q. What test year is being used in this case?

A. APS' filing is based on the historic test year ended December 31, 2010. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. In general, the test year concept is typically applied in the following manner. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are commonly annualized based on end of test year levels.[9] This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent

[9] In the current APS base rate case, APS has extended the payroll annualization and the depreciation expense annualization to levels based on information beyond the end of the 2010 test year.

with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

Q. In the current APS rate case, do the Company's and Staff's filings reflect a significant modification to the 2010 test year information used to develop APS" jurisdictional rate base?

A. Yes. Both APS' and Staff's filing in the current APS rate case include adjustments to rate base and operating expenses for post-test year plant. APS' proposed adjustment is for estimated post-test year plant that APS projects will be in service by June 30, 2012, which is 18 months beyond December 31, 2010, the end of the test year. Staff's presentation reflects post test year plant that has either already been placed into service or which will have been placed into service and which can at a later point in the proceeding be verified as having been placed into service through March 31, 2012. APS has indicated in response to Staff discovery that it will have March 31, 2012 information available approximately 30 days after that date. The use of information through March 31, 2012 should therefore result in verifiable amounts being available for review in time for an open meeting at the Commission to consider APS' base rate increase request.

APS' presentation reflects changes in the balances from accumulated depreciation and certain changes to Accumulated Deferred Income Taxes ("ADIT") that are projected to occur through June 30, 2012. Staff's presentation includes changes in accumulated depreciation at current depreciation rates occurring through March 31, 2012. Staff also proposes to include changes in ADIT through that same date, pending satisfactory resolution of a potential tax normalization issue raised by APS.[10]

[10] See, e.g., APS' response to STF 15.13, and the discussion of ADIT in conjunction with Staff rate base adjustment B-6, herein.

Q. How does Staff propose to adjust for post test year plant, accumulated depreciation and ADIT at March 31, 2012?

A. Staff currently has placeholder adjustments for those items based on known information through August 2011, which was provided in APS' response to STF 6.55, and updated projections by APS for changes through March 31, 2012 that were provided by APS in response to other Staff discovery. As stated by APS in response to STF 27.2 concerning plant, STF 27.8 concerning accumulated depreciation and STF 27.9 concerning ADIT, APS anticipates having actual December 31, 2011 amounts available 30 days after the close of the year, and APS anticipates having March 31, 2012 amounts available 30 days after the close of that quarterly period. Staff currently intends to update its current placeholder adjustments for post test year plant, accumulated depreciation and ADIT to use those actual known amounts once they are provided by APS and can be reviewed by Staff. The incorporation of such actual information for March 31, 2012 post test year plant, accumulated depreciation and ADIT may require a compliance filing by APS to be made before a final decision is issued, and for an opportunity for Staff and other parties to review and comment upon such information, so that post test year amounts for plant, accumulated depreciation and ADIT can be incorporated into the APS base rate revenue requirement in time for a final decision on or about July 1, 2012.

D. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-7 and net operating income adjustment Schedules C-

1 through C-16. The revenue requirement for APS was based upon the ACC jurisdictional adjusted results.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended fair value rate of return on Staff's proposed FVRB. The rate base and operating income amounts are taken from Schedules B and C, respectively. The weighted average cost of capital of 8.28 percent, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience, as are the derivation of Staff's two options for the fair value rate of return. Schedule D presents the weighted average cost of capital and fair value rate of return recommended in the prefiled testimony of Mr. Parcell.

The operating income excess or deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1. Line 8 shows APS' requested additional base rate increase on the FVRB increment. Line 9 shows a comparison of the total base rate revenue deficiency or excess from APS' original filing using Staff's recommended adjustments.

Q. What is shown on Schedule A, page 1, lines 10 and 11?

A. Lines 10 and 11 of Schedule A show the amount of base rate revenues from sales to ultimate customers and the approximate percentage change in base rate revenue, based on APS' originally filed request and Staff's recommended adjustments.

Q. What is shown on Schedule A, page 2?

A. Schedule A, page 2, presents a reconciliation of the base rate revenue requirement change recommended by Staff with the corresponding amounts from APS' original filing. The approximate revenue requirement impact of each Staff adjustment is shown.

Q. What is shown on Schedule A-1?

A. Schedule A-1 shows the development of the gross revenue conversion factor.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in APS' filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6566, which compares with the GRCF of 1.6532 used in APS' filing. APS did not include a component for uncollectible revenue in its GRCF calculation. Staff updated the GRCF to include an uncollectible revenue component. Due to the variances that occur with uncollectibles based on the level of revenue, Staff believes it can be appropriate to include the uncollectible revenue component in the GRCF calculation. In the current rate case, APS has not proposed a pro forma adjustment for uncollectibles expense. APS' response to STF 25.11 notes that the uncollectible rate of 0.21 percent was applied to revenue in 2008, 2009 and 2010. As shown on Schedule A-1, Staff has used the uncollectibles rate of 0.21 percent in deriving the GRCF.

Q. What is shown on Schedule B?

A. Schedule B presents APS' proposed adjusted test year Original Cost and Fair Value rate bases and Staff's proposed adjusted test year Original Cost and Fair Value rate bases. The beginning rate base amounts presented on Schedule B are taken from the Company's amended filing for the test year, specifically APS Schedule B-1. Staff's recommended adjustments to rate base are summarized on Attachment RCS-2, Schedule B.1. Attachment RCS-2 includes a separate Schedule B.1 for adjustments to Original Cost rate base and for adjustments to Reconstruction Cost New Depreciated ("RCND") rate base. Each of these adjustments is discussed in this testimony.

Schedules B-1 through B-7 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is APS' adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to APS' adjusted test year revenues and expenses are summarized on Attachment RCS-2, Schedule C.1. Each of these adjustments is discussed in my testimony.

Schedules C-1 through C-16 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by APS and the capital structure and cost of capital that is recommended by Staff witness Parcell.

Schedule D also presents the derivation of Staff's recommended Fair Value rate of return for use with the Staff's adjusted Fair Value rate base.

E. Staff's Fair Value Rate of Return Presentation

Q. What information on the FVROR is Staff presenting to the Commission in this proceeding?

A. Staff is presenting the Commission with two alternatives for the FVROR to be applied to APS' adjusted Fair Value rate base. As shown in Schedule D, Staff alternative 1 applies a zero cost rate to the FV increment and produces a Fair Value rate of return of 5.74 percent. Under alternative 2, a return of 1.0 percent is applied to the FV increment and produces a Fair Value rate of return of 6.05 percent. The 1.0 percent is developed by Staff witness David Parcell and represents a point within a range from zero to a "real" risk-free rate of return *i.e.* a risk-free rate of return less inflation. The testimony of Staff Witness David Parcell addresses these alternative methods of deriving a FVROR.

F. Fair Value Rate of Return on Fair Value Rate Base

Q. How was the Fair Value rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the Fair Value rate base was determined by averaging Original Cost and RCND rate base information. For purposes of this presentation, Staff has used the Company's RCND information as the starting point for the fair value rate base.

Q. How did APS determine the Fair Value rate of return to apply to Fair Value rate base in its filing?

A. As shown on Attachment RCS-2, Schedule A, in column B (which reproduces the revenue deficiency calculation from APS' Schedule A-1), the Company calculated a revenue deficiency of $54.610 million on its proposed Original Cost and FVRB base, and adds $40.883 million for an additional revenue requirement on the FVRB increment, based on a 1.0 percent return on the FVRB increment, to derive its total requested base rate revenue increase of $95.493 million.

RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Attachment RCS-2, Schedule B and the adjustments to APS' proposed rate base are shown on Schedule B.1. Attachment RCS-2 contains a separate Schedule B.1 for adjustments to original cost rate base and to RCND rate base. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis are presented below:

$000's	APS	Staff	Difference
Summary of Rate Base	Schedule B-1	Schedule B	
Original Cost Rate Base	$ 5,720,277	$ 5,662,998	$ (57,279)
RCND Rate Base	$ 10,728,532	$ 10,671,253	$ (57,279)
Fair Value Rate Base	$ 8,224,405	$ 8,167,126	$ (57,279)

Post-Test Year Plant

Q. How is inclusion of post-test year plant in rate base an issue in the current APS rate case?

A. As described below in more detail, APS has proposed to include several hundred million dollars in rate base for post-test year plant. Some of this amount relates to amounts that were included in construction work in progress ("CWIP") as of December 31, 2010, the end of the test year, which APS has since placed into service, or projects that would be placed into service, at various points in time before new base rates resulting from this proceeding are anticipated to become effective.

Q. Is the inclusion of post-test-year plant in rate base an exceptional ratemaking treatment and up to the discretion of the Commission?

A. Yes, it is. Staff's understanding is, in specific instances, the Commission has allowed a utility to include CWIP, or alternatively post-test year plant additions, in rate base, but the Commission's general practice has been to not allow CWIP to be included in rate base. That said, the inclusion of CWIP in rate base is an exceptional ratemaking treatment.

Q. Please elaborate on how including CWIP or post-test-year plant in rate base is an exceptional ratemaking treatment.

A. CWIP, as the title designates, is not plant that is completed and providing service to ratepayers during the test year. During the test year, it is not used or useful in providing electric service to a utility's customers. The ratemaking process is predicated on an examination of the operations of a utility to insure that the assets upon which ratepayers are required to provide the utility with a rate of return are prudently incurred and are both used and useful in providing services on a current basis. Facilities in the process of being built are not used or useful. The ratemaking process therefore excludes CWIP from rate base until such projects are completed and providing service to ratepayers in the context of a test year that is being used for determining the utility's revenue requirement. In the current APS rate case, the test year is the twelve months ending December 31, 2010, and the construction projects the Company seeks to include in rate base were not providing service during that period. The Company claims that the construction projects it is requesting for inclusion in rate base will be in service by the time rates in this proceeding take effect. In APS' last base rate case, Docket No. E-01345A-08-0172, the Commission approved a Settlement Agreement, which allowed post test year plant beyond the historic test year. The Settlement Agreement (at ¶ 3.4) cited the Signatories' desire to enhance APS' ability to retain and improve its current investment grade rating, thereby allowing APS to attract capital at reasonable rates and to also optimize its operational flexibility. For purposes of this case, for the reasons just cited from the Settlement Agreement, Staff is proposing to include in rate base post-test-year plant that can be verified as being in service on or before March 31, 2012. Based on that determination, I have reflected a rate base adjustment for post-test-year plant that has been or will be placed into service by March 31, 2012, one full year and three months after the test year, as post-test year plant in rate base.

Q. What post-test year plant additions is APS requesting?

A. In its filing, APS has requested post-test year plant additions for plant it anticipates will be placed into service by June 30, 2012.

Q. What is Staff's position on the inclusion of post-test-year plant in rate base for APS?

A. As described above, Staff proposes to include plant that is placed into service by March 31, 2012 as post-test-year plant.

Q. Have you made any adjustments to APS' proposed rate base amounts for any of these items?

A. Yes. I have made adjustments to APS' proposed amounts for post-test year Plant in Service in Staff rate base Adjustments B-1 through B-4. I have also adjusted Accumulated Depreciation for changes occurring through March 31, 2012 in Staff rate base adjustment B-5, and have adjusted ADIT for some of the ADIT changes occurring through March 31, 2012 in Staff rate base adjustment B-6. Each of these adjustments is currently based on APS' estimates, and should therefore be viewed as a placeholder. As described above, ultimately, Staff proposes to use actual March 31, 2012 balances for post test year plant additions, accumulated depreciation and ADIT.

Q. What policy guidance are you following concerning the amount of post-test year plant additions that Staff proposes be included in rate base?

A. Staff has determined in the current APS base rate case that post-test-year plant additions that can be verified as having been placed into service by March 31, 2012 should be included in rate base as post-test-year plant.

Q. What rate base adjustments have you made to APS' proposed miscellaneous post-test year plant additions based on that guidance?

A. Staff Adjustments B-1 through B-4 reflect the impact of this recommendation for post test year plant. The amounts of post-test-year plant that APS has requested that are not in service or projected to be in service by March 31, 2012 have not been included in rate base as plant in service by Staff.

I have also made related adjustments for Depreciation and Property Tax Expense as it relates to those adjustments to post-test year plant.

B-1. Post-Test Year Plant Additions - Solar

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Solar Plant.

A. The Company made a pro forma adjustment to increase its rate base by including solar plant additions totaling approximately $277.411 million on a total Company basis and $267.979 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-1, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for solar plant additions through March 31, 2012 that APS provided in response to STF 27.4(a), Staff has reflected post test year solar plant additions through March 31, 2012 of $240.759 million on a total Company basis and $232.573 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year solar plant additions by $35.406 million, as shown on Schedule B-1, column F.

B-2. Post-Test Year Plant Additions - Fossil

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Fossil Plant.

A. The Company made a pro forma adjustment to increase its rate base by including fossil plant additions totaling approximately $156.269 million on a total Company basis and $150.956 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-2, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for fossil plant additions through March 31, 2012 that APS provided in response to STF 27.4(c), Staff has reflected post test year fossil plant additions through March 31, 2012 of $131.985 million on a total Company basis and $127.498 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year fossil plant additions by $23.458 million, as shown on Schedule B-2, column F.

B-3. Post-Test Year Plant Additions - Nuclear

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Nuclear Plant.

A. The Company made a pro forma adjustment to increase its rate base by including nuclear plant additions totaling approximately $120.103 million on a total Company basis and $116.019 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-3, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for nuclear plant additions through March 31, 2012 that APS provided in response to STF 27.4(b), Staff has reflected post test year nuclear plant additions through March 31, 2012 of $101.950 million on a total Company basis and $98.483 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year nuclear plant additions by $17.536 million, as shown on Schedule B-3, column F.

B-4. Post-Test Year Plant Additions – Distribution, General and Intangible

Q. Please explain Staff's adjustment to APS' post-test year plant additions for Distribution, General and Intangible Plant.

A. The Company made a pro forma adjustment to increase its rate base by including distribution, general and intangible plant additions totaling approximately $432.984 million on a total Company basis and $423.910 million on an ACC jurisdictional basis that APS originally expected would be placed into service by June 30, 2012. At the end of the test year, these projects had not been completed and were not recorded as Plant in Service. APS contends that these construction projects will close to Plant in Service by June 30, 2012, *i.e.* or by the time APS expects the new rates in this proceeding to take effect. APS claims that this justifies their inclusion in rate base in this proceeding. As shown on Attachment RCS-2, Schedule B-4, based on actual information through August 2011 that was provided in APS' response to STF 6.55 and updated projections from APS for distribution plant additions through March 31, 2012 that APS provided in response to STF 27.4(d) and (e), Staff has reflected post test year distribution, general and intangible plant additions through March 31, 2012 of $378.649 million on a total Company basis and $370.714 million on an ACC jurisdictional basis. This results in an adjustment to reduce APS' originally filed projection of post test year distribution, general and intangible plant additions by $53.196 million, as shown on Schedule B-4, column F.

Q. Are Staff rate base Adjustments B-1 through B-4 related to corresponding income statement adjustments?

A. Yes. Staff rate base adjustments B-1 through B-4 for post test year plant additions through March 31, 2012 are related to Staff's operating income statement adjustments C-4 through C-7, which reduces APS' proposed pro forma adjustment to Depreciation and Property Tax Expense as it relates to the post-test year plant additions removed from APS' proposed rate base as shown on Schedules B-1 through B-4.

End of Test Year Construction Work in Progress In-Service by March 31, 2012

Q. In APS' last base rate case, Docket No. E-01345A-08-0172, how was the post test year plant adjustment determined?

A. In APS' last rate case, the post test year plant adjustment was determined by reviewing the December 31, 2007 end of test year balance of CWIP and allowing post test year plant additions for the components of that balance that were being placed into service by a June 30, 2009 date that was eighteen months after the end of the test year. Specifically, in Docket No. E-01345A-08-0172, the portion of APS' December 31, 2007 CWIP projects that were projected to be placed into service by December 31, 2008 were included by Staff in rate base as post-test-year plant. Ultimately, the Settlement Agreement in that docket provided for a return on and of such post-test year through June 30, 2009, eighteen months beyond the test year ending December 31, 2007.[11]

Q. What is APS" CWIP balance at December 31, 2010?

A. According to APS' responses to STF 22.7 and 27.13, APS' December 31, 2010 CWIP balance, exclusive of nuclear fuel, was $369.413 million.

[11] This was noted in the Settlement Agreement at paragraph 3.4.

Q. **Have some of the projects that were in CWIP at December 31, 2010 since been placed into service?**

A. Yes. Many of the proposed post-test year plant additions that were in CWIP as of December 31, 2010 have been placed into service and closed to Plant in Service. For example, APS' responses to STF 22.7 and 27.13 identified the amount of December 31, 2010 CWIP that was placed into service by August 31, 2011 as $161.191 million.

Q. **Does APS anticipate that some additional amounts of December 31, 2010 CWIP will be placed into service from September 1, 2011 through March 31, 2012?**

A. Yes. APS' response to STF 27.13 shows that APS expects that $90.597 million of the December 31, 2010 CWIP will be placed into service between September 1 and December 31, 2011 and an additional $28.170 million will be placed into service by March 31, 2012.

Q. **Does APS anticipate that some amounts of its December 31, 2010 CWIP balance will <u>not</u> be placed into service by March 31, 2012?**

A. Yes. APS' response to STF 27.13 shows that APS expects that $89.455 million of the December 31, 2010 CWIP will <u>not</u> be placed into service by March 31, 2012.

Q. **Is Staff making a specific adjustment for the portions of the December 31, 2010 CWIP balance that are anticipated to be placed into service by March 31, 2012 in the current APS rate case?**

A. No, not at this time. As explained above, in the current APS rate case, Staff has followed a similar approach to addressing post test year plant additions that APS proposed in its filing, which involves reflecting post test year plant additions for plant that is placed into service by a certain date. For the date for post test year plant in the current APS rate case, APS proposes using June 30, 2012 and Staff has used March 31, 2012. The plant reflected dramatically. ADIT represents the cumulative consequences of the differences between tax and book accounting.

Q. What is the main source of ADIT for utilities?

A. The main source of ADIT for utilities is depreciation. Financial reporting reflects the economic decline of an asset over its useful life. By contrast, the tax law reflects a conscious policy by Congress to promote the acquisition of certain types of assets. Congress implemented this policy by enacting accelerated depreciation, which allows the claiming of tax depreciation deductions using a pattern that is a good deal more rapid than the economic consumption of the asset. The accelerated deductions lower income taxes due and thereby produce a cash benefit to the company making the investment. Depreciation, both book and tax, is generally limited to the cost of an asset.[13] Accelerated tax depreciation essentially allows tax deductions that would have been claimed at a later point in time to an earlier point in time. It generally does not alter the total quantity of deductions. The primary purpose is to encourage investment by providing an income tax savings to the taxpayer.

Q. What is the nature of accelerated tax depreciation?

A. By accelerating deductions, Congress extended an interest-free loan from the Federal government to taxpayers who acquire business assets. This capital investment subsidy could have taken the form of a straight governmental loan program. Instead, Congress chose to use the tax system to extend and receive repayment of the loan. This is where ADIT comes in. ADIT represents the obligation on the part of the Company to repay the loan that was extended by the government. Conceptually, ADIT is funded by ratepayers

[13] The capitalized cost of an asset can be different for financial reporting and income tax purposes, due to different capitalization accounting methods.

through the payment of a utility's Deferred Income Tax Expense, which is included as an operating expense in establishing a utility's revenue requirement and base rates.

Q. Is ADIT unique to utilities?

A. No. Under GAAP, all companies reflect ADIT. This is because governmental loans are made to all types of enterprises and, in each case, the economics are the same. In the case of utilities, however, the ADIT is funded by ratepayers via the inclusion of Deferred Income Tax Expense in the setting of a utility's rates based on cost of service principles.

Q. What are the typical accounting entries for ADIT relating to accelerated tax depreciation?

A. For accelerated tax depreciation, the tax deduction typically exceeds the book depreciation expense, especially in the early years after the asset is placed into service. For illustrative purposes, if tax depreciation in a particular year exceeded book depreciation by $100 million, and the tax rate was 40%, a utility would make the following accounting entries to record the impact on ADIT:

Dr. Deferred Income Tax Expense	$40 million
Cr. Accumulated Deferred Income Taxes	$40 million

In this example, the Deferred Income Tax expense and ADIT are each increased by $40 million. Accounting for ADIT can be a complicated area. The above simplified illustration is not intended to explain the complexities, but rather to merely provide some basic content from an accounting perspective to help conceptualize the rate making treatment.

Q. How is ADIT treated in ratemaking?

A. Because ADIT represents a no-cost element of the financing of the asset being depreciated, ADIT associated with the assets included in rate base is reflected in Arizona ratemaking as a reduction in rate base (the predominant practice). (In some regulatory jurisdictions, the ADIT is reflected as a zero cost component of the capital structure.) In either case, ADIT associated with assets included in rate base reduces the return component of the cost of service.

Q. Ideally, should the ADIT amount be updated through the same date as post test year plant and accumulated depreciation, in the determination of rate base?

A. Yes. Because rate base is being adjusted to reflect post-test-year plant additions placed into service by March 31, 2012, ideally the related impacts on ADIT through that same date should also be reflected. This would reflect that the post test year plant has in part effectively been financed by a combination of growth in the accumulated depreciation balance and by cost free capital in the form of ADIT.

Q. How have additional tax deductions become available to APS as the result of changes in the federal income tax laws?

A. On December 17, 2010, President Obama signed legislation known as the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. That Act provides for 100 percent depreciation bonus for qualifying capital investments placed in service after September 8, 2010 through December 31, 2011. For equipment placed in service after December 31, 2011 and through December 31, 2012, the bill provides for 50 percent bonus tax depreciation. The Small Business Jobs Act of 2010, which contained 50 percent depreciation bonus, still applies to purchases made between January 1, 2010 and September 7, 2010. In summary:

- Bonus tax depreciation helps businesses that buy new equipment cut their tax bill.
- The bonus tax depreciation applies, among other things, to purchases of tangible personal property (including construction, mining, forestry, and agricultural equipment) with a MACRS recovery period of 20 years or less.
- To qualify, the equipment must have been purchased and placed in service.
- The bonus tax depreciation applies to new equipment only.
- This bonus tax depreciation is allowed for both regular and alternative minimum tax purposes.
- The bonus tax depreciation is discretionary; the taxpayer need not claim the depreciation bonus.
- The Depreciation Bonus will expire at the end of 2012.
- For 2011, the tax depreciation bonus is 100 percent for qualifying property.

Q. **What are the implications for a regulated utility, such as APS?**

A. For a regulated public utility, such as APS, that normalizes its federal income tax expense related to tax depreciation, the bonus federal income tax depreciation should reduce current federal income tax expense. There are also related impacts on deferred income tax expense and ADIT. Deferred federal income tax expense and ADIT, which is a rate base offset, are each increased by similar amounts. In general, the increase to deferred federal income tax expense and the increase to ADIT are the result of the same journal entries. In situations where the utility has adequate positive taxable income to fully utilize the deductions, for income statement purposes, the impacts on current and deferred income tax expense will generally offset each other, and there should be no net effect. For rate base, however, the substantially increased ADIT, which is non-investor supplied cost-free capital, provides a significant reduction.

Q. Has the task of updating the ADIT balance to March 31, 2012 been complicated in the current APS rate case by other factors?

A. Yes. As described in APS' responses to STF 15.13, AECC 1.11, STF 19.14 and 19.15, APS anticipates realizing substantial amounts of 2011 and 2012 bonus tax depreciation. APS' response to STF 15.13(c), for example, indicates that, based on the updated calculations for post test year plant provided in APS' supplemental response to STF 6.55, the estimated ADIT impacts from 2011 and 2012 bonus tax depreciation are anticipated by APS to be in a range of $79 million to $128 million, as shown at APS14831. APS has cautioned, however, that without guidance from the IRS that explicitly allows inclusion of ADIT balances in rate base, APS believes that using such a methodology would not be appropriate and could result in extremely unfavorable tax consequences for the Company and its customers.[14] APS' response to STF 19.14(a) addresses and explains the concerns in additional detail.

Additionally, APS' response to STF 19.15(c) indicates that, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. How does a federal income tax net operating loss ("NOL") occur?

A. A NOL is created in any year in which the aggregate income reported on a taxpayer's tax return is exceeded by the aggregate deductions claimed on that return. An NOL results when a taxpayer's deductions exceed the taxable income in a tax year.

[14] See, e.g., APS' response to STF 15.13(c), (d), and (e), etc.

Q. How can an NOL provide for future tax savings?

A. A federal income tax NOL can be carried forward for 20 years and can be applied against future taxable income to reduce tax expense.

Q. In general, is it possible to relate specific deductions to a Company's NOL?

A. No. In order to relate specific deductions to the Company's NOLs, there would have to be deduction ordering rules. As a general matter, the tax law contains no ordering rules for deductions. Thus, for most purposes, it does not relate an NOL to any specific deductions. Consequently, as a general matter, it is not possible to relate any specific deductions to the NOL that APS anticipates for 2011.

Q. Did APS pay federal income tax for the 2010 test year?

A. APS' response to STF 19.15, concerning whether APS paid any federal income tax for 2010, states that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. You mentioned that in a number of responses to discovery, such as STF 15.13 and others, APS has cautioned about updating the ADIT balance to March 31, 2011 without guidance from the IRS that explicitly allows inclusion of those ADIT impacts in rate base. Has APS applied for any such guidance from the IRS on how the actual March 31, 2011 ADIT balance could be reflected in the determination of rate base to match the use of March 31, 2011 balances for plant and accumulated depreciation?

A. No. APS' response to STF 19.14(b) states that:

> A draft of the guidance (a Private Letter Ruling) that APS would need to seek from the IRS has not yet been prepared, and could take several months to draft. Additionally, outside tax counsel would be needed to properly draft and file such a request for guidance. APS believes that the associated

expenditures should not be made until it becomes readily apparent that no other options are available.

Q. What other options has APS suggested?

A. In response to STF 19.14(c), with regard to the reflection of ADIT associated with post test year plant, APS proposes one of two options[15]: (1) make the adjustment for post test year plant in a manner similar to the 2009 rate case settlement and do not reduce the post test year plant additions for post test year ADIT[16], or (2) permit APS to use a complete future test year period ending June 30, 2012 for all rate case items.

Q. Are those APS suggestions under consideration by Staff?

A. Only the first one. As explained above, Staff would consider making the rate base adjustment for post test year plant in a manner similar to how that was done in APS' last base rate case, Docket No. E-01345A-08-0172, which involved using the end-of-test-year CWIP balance for items within that balance placed into service within a certain time after the test year.

With respect to the second suggestion made by APS, APS does not explain how or when its filing would be updated for a "complete future test year period ending June 30, 2012," and does not address or explain how that would not constitute essentially filing an entirely new rate case with a different test year. Staff does not believe that alternative is feasible nor has any merit in the context of the current APS base rate case.

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[15] A complete copy of APS' response to STF 19.14 is included in Attachment RCS-4, attached to this testimony.

[16] APS states that this would "allow post test year additions in a manner consistent with the 2009 rate settlement." However, as noted above, the 2009 rate settlement concerning post test year plant was based on allowing the specific components of the December 31, 2007 end-of-test year CWIP that were being placed into service by June 30, 2009. The proposal by APS for post test year plant and related changes to accumulated depreciation and ADIT in the current base rate case, as explained above, is somewhat different.

Q. **Given the uncertainty regarding how to appropriately reflect the update to the ADIT balance to March 31, 2012 to match the post test year plant and accumulated depreciation adjustments, how have you reflected the post test year adjustment for ADIT at this time?**

A. As shown on Attachment RCS-2, Schedule B-6, page 1, at this time, the adjustment of the rate base offset for ADIT only reflects removal of the April 1 through June 30, 2012 amounts for post test year ADIT contained in the APS rate base adjustments for post test year plant. This results in decreasing jurisdictional ADIT, and increasing rate base, by $1.726 million.

Q. **What is shown on Schedule B-6, page 2?**

A. Schedule B-6, page 2, shows total Company and ACC jurisdictional amounts for the ADIT components that are typically reflected in the determination of APS' rate base, and shows how the net credit-balance amount of ADIT has grown through actual data provided by APS at July 31, 2011, and is estimated by APS to increase further through March 31, 2012. APS' original filing reflected a jurisdictional offset to rate base for ADIT of approximately $1.615 billion.[17]

APS' October 26, 2011 update filing reflects a jurisdictional offset to rate base for ADIT of approximately $1.615 billion.[18] In comparison, as of July 31, 2011, the actual jurisdictional ADIT balance had grown to approximately $1.658 billion.[19] Additionally, the information provided by APS in response to STF 20.1 shows the estimated jurisdictional ADIT balance at March 31, 2012 of approximately $1.723 billion.[20] The differences between these amounts and the jurisdictional ADIT reflected in APS' filing

[17] See Attachment RCS-2, Schedule B-6, line 31.
[18] See Attachment RCS-2, Schedule B-6, line 33.
[19] See Attachment RCS-3, Schedule B-6, column A, line 30.
[20] Id, column I, line 30.

are large and highlight the importance of appropriately updating the ADIT balance to match the time frame with updating rate base for plant and accumulated depreciation.

Q. How did you determine the RCND adjustment for ADIT?

A. In this case, the RCND adjustment for ADIT is the same as the Original Cost rate base adjustment for ADIT.

B-7 Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's working capital request consists of six separate subcomponents. As shown on APS' Schedule B-5, the subcomponents are:

(1) a negative Cash Working Capital balance of negative $101.57 million based on a lead/lag study on a total company basis;

(2) a year-end Materials and Supplies balance of $181.414 million on a total company basis;

(3) a year-end Fuel (Coal and Oil) balance of $21.575 million on a total company basis;

(4) a year-end Fuel (Nuclear) balance of $108.794 million on a total company basis;

(5) a year-end Prepayments balance of $23.346 million on a total company basis; and

(6) a year-end Special Deposits & Working Funds balance of $219,000 on a total company basis.

As shown on Company Schedule B-5, APS' calculated a total company basis amount of Working Capital allowance of $233.778 million. On APS' Schedule B-1, line 19, APS has reduced the Cash Working Capital component of that by $14.220 million, bringing the total company amount to \$219.558 million. The corresponding ACC jurisdictional amount of rate base APS is requesting for Working Capital is \$202.206 million, as shown on APS' Schedule B-1, page 1, column F, line 19.

Q. Has Staff adjusted any of those working capital components?

A. Yes, only one, the cash working capital component. Staff has accepted APS' working capital components which involve balances at December 31, 2010, the end of the test year, but has adjusted the Company's cash working capital request to reflect Staff adjustments to operating expenses. Staff's adjustment to cash working capital is discussed below.

B-7.1. Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's payment of cash expenditures, on an aggregate basis, occurs before the cash receipt of utility revenue, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does APS have a positive or negative cash working capital requirement?

A. APS has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did APS present a lead/lag study in support of its cash working capital requirement?

A. Yes, APS performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with its work papers in this case.

Q. Are you recommending any revisions to APS' cash working capital request?

A. Yes. I have reflected the impact of Staff's adjustments to operating expenses. I have also synchronized the calculation of cash working capital with Staff's recommended revenue increase in terms of updating the cash expenses for income taxes and interest.

Q. What is the result of your cash working capital calculation?

A. As shown on Schedule B-7, page 1, APS' filed cash working capital request should be increased by approximately $10.467 million on an ACC jurisdictional basis.

Q. Were there certain Staff adjustments to APS' operating expenses that are primarily attributable to that increase in the allowance for cash working capital?

A. Yes. The increase in the allowance for cash working capital, as noted above, is shown on Attachment RCS-2, Schedule B-7, page 1. As shown on line 18, Staff's adjustment to incentive compensation expense increased the jurisdictional allowance for cash working capital by approximately $10.3 million. As shown on lines 41 and 42, Staff's adjustment to income tax expense increased the jurisdictional allowance for cash working capital by $851,000, and property tax expense increased the jurisdictional allowance for cash working capital by $646,000. Those were the largest impacts. As shown on Schedule B-

7, page 1, Staff's other adjustments to other operating expenses increased the cash working capital allowances in some instances and decreased it in others.

Other Rate Base Updates

Q. Please explain Staff's review of changes in APS' balance sheet accounts for Other Rate Base Updates.

A. As described above, Staff has reflected post test year changes for plant through March 31, 2012, and related adjustments for accumulated depreciation and ADIT through that same date.[21] In order to assure that rate base is updated for the use of actual March 31, 2012 information in a consistent and balanced manner, Staff proposes to review, and may propose adjustments for changes in, other balance sheet accounts through that date that are currently reflected in APS' rate base on the basis of December 31, 2010, end-of-test year recorded balances.

ADJUSTMENTS TO OPERATING INCOME

Discussion of selected company adjustments

Q. Are there certain Company proposed adjustments that you would like to address before discussing Staff's adjustments?

A. Yes. There are two Company adjustments that relate to provisions contained in the Settlement Agreement that was reached by the parties in APS' last rate case, Docket No. E-01345A-08-0172. APS' adjustment 17 removes Schedule 3 revenue and the Company's adjustment 23 amortizes deferred pension and other post employment benefit (OPEB) costs. Both of these adjustments relate to special accounting treatments that were

[21] As noted above, the ultimate amounts of these adjustments will depend on actual information to be provided by APS, which APS anticipates having available by April 30, 2012. Additionally, an adjustment to fully reflect ADIT changes through March 31, 2012 is pending additional information concerning how a normalization concern raised by APS in discovery responses can be resolved.

provided for in the Settlement Agreement that was approved by the Commission in No. E-01345A-08-0172.

APS' filing also reflects the Company making two adjustments, to remove expense for supplemental executive retirement plan and stock-based compensation, which appear to be consistent with prior Commission orders, and which are the types of adjustments that would typically be made by Staff and/or RUCO in recent utility rate cases, and would be made in the current case by Staff if such costs were not already being removed by APS in the current case.

Finally, APS proposed a new adjustment in its October 26, 2011 update, related to transmission costs, upon which Staff has reserved judgment on this new adjustment at this time.

Schedule 3 Revenues

Q. What are Schedule 3 revenues?

A. Schedule 3 of APS' tariff relates to fees that are collected by the Company for line extensions.

Q. What unusual accounting was provided for Schedule 3 revenues in the Settlement Agreement that was approved by the Commission in No. E-01345A-08-0172?

A. Section X of the Settlement Agreement at paragraph 10.1 provided for APS to record Schedule 3 receipts as revenue during the period January 1, 2010 through the earlier of December 31, 2012 or the conclusion of APS' next general rate case. Prior to that, APS had recorded Schedule 3 receipts as Contributions in Aid to Construction ("CIAC").

Recording receipts for line extensions as CIAC is the standard way of accounting for such receipts under the Uniform System of Accounts for electric utilities.

Q. Please discuss the Company's adjustment to remove Schedule 3 revenues.

A. APS proposes to discontinue the special accounting treatment – i.e., recording Schedule 3 receipts as revenue – that had been provided by the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172, and to again resume the standard accounting for such receipts as CIAC. Accordingly, the Company's adjustment no. 12 removes $18.660 million of Schedule 3 revenues from revenues.

Q. How is CIAC typically treated for ratemaking purposes?

A. CIAC is typically treated for ratemaking purposes as an offset to rate base. The rate base offset amount related to CIAC is typically based on the unamortized CIAC balance, less an income tax impact that is accounted for in the balance of ADIT.

As a simplified example, if a utility had $100 million of unamortized CIAC (and there was a 40 percent combined state and federal income tax rate), rate base would be reduced by approximately $60 million ($100 million of CIAC less $40 million of ADIT).

The amortization of CIAC is typically reflected for ratemaking purposes as an offset to a utility's depreciation expense.

Q. What amounts did APS expect for Schedule 3 receipts in Docket No. E-01345A-08-0172?

A. As stated in paragraph 10.2 of the Settlement Agreement in Docket No. E-01345A-08-0172, APS estimated that its Schedule 3 revenues would be $23 million in 2010, $25 million in 2011 and $49 million in 2012.

Q. What amount of Schedule 3 receipts did APS record as revenue in the 2010 test year?

A. In the 2010 test year, APS recorded $18.660 million of Schedule 3 receipts as revenue.

Q. Does Staff agree with the Company's proposed adjustment to remove the Schedule 3 revenue?

A. Yes. The recording of Schedule 3 receipts as revenue represented an unusual accounting treatment and was instituted in the context of the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172 primarily as a temporary measure to help APS manage its earnings and support its credit rating during the period between base rate cases. Under ordinary circumstances, Staff supports the recording of receipts that utilities receive for line extensions in accordance with the standard accounting, i.e., recording such receipts as CIAC. Consequently, Staff agrees with the conversion back to standard accounting, as CIAC, for Schedule 3 receipts. Additionally, the $18.660 million amount by which revenues are reduced in the current APS rate case is somewhat lower than the amounts of Schedule 3 revenues that APS was expected to receive from Docket No. E-01345A-08-0172, so transitioning back to the normal accounting treatment at this time, i.e., in the context of the 2010 test year when APS' Schedule 3 receipts were relatively low, will help to minimize the rate impacts of the transition. Consequently, Staff has accepted APS' proposed adjustment no. 17 to remove the Schedule 3 revenues.

Amortization of Deferred Pension and OPEB Costs

Q. What was provided for in the Settlement Agreement that was approved by the Commission in Docket No. E-01345A-08-0172 concerning deferrals of pension and OPEB costs?

A. Section IX of that Settlement Agreement provided for limited deferrals of Pension and OPEB costs by APS in 2011 and 2012 if such costs exceed the Docket No. E-01345A-08-0172 test year level, which the Signatories to the Settlement Agreement identified as $23.949 million.

Q. What has APS proposed in the current rate case related to that provision?

A. APS proposes in Company adjustment no. 23 to increase pre-tax operating expenses by $8.740 million in total and by $8.122 million on an ACC jurisdictional basis to reflect the recovery via amortization over a three-year period of the pension and OPEB cost deferral authorized in Decision No. 71448.

Q. Does Staff agree with that APS adjustment in principle?

A. Yes. Staff agrees that the adjustment proposed by APS is consistent in theory and concept with the Settlement Agreement provision for limited deferrals of Pension and OPEB in 2011 and 2012 if such costs exceed the test year level used in Docket No. E-01345A-08-0172.

Q. Does Staff have any concerns about the amounts used by APS?

A. Yes. APS' proposed adjustment is based on 2011 and 2012 estimates of pension and OPEB costs that were available to APS when APS prepared its filing. Staff has not been able to verify the amounts of APS' actually incurred 2011 or 2012 pension and OPEB costs, as those accounting periods have not yet closed. Moreover, the 2011 information used by APS to compute its adjustment does not appear to reflect the latest actuarial valuation, which was presented to the Company on May 20, 2011 by Towers Watson, as described in APS' response to STF 27.1(i).

Q. How does Staff propose to address such concerns in the context of the current APS rate case?

A. Staff proposes to address such verifiability concerns in the context of the current APS rate case by seeking updated information from APS on actual 2011 and 2012 pension and OPEB costs, and may adjust the estimated amounts used by APS, if such an adjustment becomes warranted.

Supplemental Executive Retirement Benefits

Q. Please discuss APS' proposed adjustment to remove expense for Supplemental Executive Retirement Benefits.

A. APS' adjustment No. 25 reduces pre-tax operating expenses by $8.492 million in total and $7.892 million on an ACC jurisdictional basis to remove expense for benefits under the Supplemental Executive Retirement Plan ("SERP").

Q. Can you please provide a general description of SERPs?

A. The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

Q. Is the removal of expense for SERPs consistent with Commission precedent?

A. Yes. The removal of expense for SERP is consistent with a series of Commission decisions in which the SERP expense has been removed from utility rates, including Commission decisions in rate cases involving APS and other utilities that are regulated by the Commission. In Decision No. 68487, in a Southwest Gas Corporation rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Decision No. 68487 that:

> Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

In a UNS Gas, Inc. rate case, in Decision No. 71623 at pages 33-34, the Commission stated:

> [I]n Decision No. 69663, we disallowed SERP expenses for APS based on the finding made in the earlier Southwest Gas proceeding. (Decision No. 69663, at 26-27.) In the prior UNS Electric case (Decision No. 70360, at 22), we also excluded SERP costs stating '[w]e see no reason to depart

> from the rationale on this issue in the most recent UNS Gas rate case...' In the most recent Southwest Gas case (Decision No. 70665, at 17-18), we again found that SERP expenses should not be recoverable from ratepayers.
>
> We see no reason to depart from the rationale on this issue in all of the recent cases cited above, that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits (currently $240,000). As has been stated in prior cases, the Company's shareholders may provide these additional retirement benefits but ratepayers should not be subject to this additional burden.
>
> We therefore adopt the recommendations of Staff and RUCO and disallow...SERP expenses proposed by UNS Gas.[22]

At page 28 of that Decision, the Commission stated:

> ... the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rationale on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.

In Decision No. 71914 (September 30, 2010), the Commission also disallowed UNS Electric's SERP cost in Docket No. E-04204A-09-0206, stating at page 31 that:

> We see no reason to depart from the rationale on this issue in all of the recent cases cited above, that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits (currently $240,000). As has been stated in prior cases, the Company's shareholders may provide these additional retirement benefits but ratepayers should not be subject to this additional burden.
>
> We therefore adopt the recommendations of Staff and RUCO and disallow ... SERP expense proposed by UNSE.

[22] See Decision No. 70011 at pages 27-29.

SERP expense was also removed by Staff in APS' last rate case, Docket No. E-01345A-08-0172 and such removal was incorporated into the Settlement Agreement revenue requirement that was approved by the Commission in Decision No. 71448 (December 30, 2009).

Q. Does Staff agree with the Company's adjustment to remove SERP expense?

A. Yes. The removal of SERP expense is consistent with several Commission orders, including those noted above, which have required the removal of such expense.

Stock Compensation

Q. What adjustment has APS proposed in the current case with regard to stock-based compensation?

A. The Company's adjustment no. 26 reduces pre-tax operating expenses by $12.421 million in total and by $11.543 million on an ACC jurisdictional basis to remove expense related to stock-based compensation.

Q. Has stock-based compensation been removed in other cases?

A. Yes. In Decision No. 69663, from a prior APS rate case, Docket No. E-01345A-05-0816 et al, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The

> Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost.
>
> We agree with Staff that APS' stock-based incentive compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "[e]nhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred, thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation.

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of APS' incentive compensation expense, specifically the stock-based compensation.

Q. Was stock-based compensation expense also disallowed in the Commission's decisions in other rate cases?

A. Yes, it was. In Decision No. 70360 at page 22, in a rate case involving UNS Electric, the Commission, in referencing a similar decision regarding Southwest Gas Corporation as well as a prior APS rate case stated:

> For these same reasons, we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees...The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663).

In Decision No. 71914 (September 30, 2010), the Commission also disallowed UNS Electric's stock-based compensation expense in Docket No. E-04204A-09-0206, stating at pages 29-30, among other things, that:

> We agree with RUCO that UNSE's proposal to include the costs of stock-based compensation should be denied. ...
>
> The Company has not presented a compelling reason to depart from previous and recent determinations on this issue.

Q. Please discuss the reasons for removing stock-based compensation.

A. Ratepayers should not be required to pay executive or management compensation that is based on the performance of the Company's (or its parent company's) stock price.

Q. Does Staff agree with the Company's adjustment to remove the expense for stock-based compensation?

A. Yes.

APS' October 26, 2011 New Update Adjustment to "Sync-Up Transformers Excluded from the FERC Formula Rate"

Q. Has APS presented a new operating expense adjustment in conjunction with its October 26, 2011 update that Staff has not reflected at this time, which you would like to discuss?

A. Yes. In particular I would like to briefly discuss one new adjustment APS made in its October 26, 2011 update, which is not being incorporated at this time into Staff's derivation of the base rate revenue requirement for APS. The new adjustment proposed by APS (APS adjustment no. 35) is described as an adjustment to "sync up the step-up transformers excluded from the FERC formula rate." This new APS adjustment does not appear to relate to any information provided by APS in discovery, nor does it appear to be supported by any APS testimony that Staff has been able to identify. Staff is also unclear at this time how this new APS adjustment relates to the continuation of APS' existing Transmission Cost Adjustment ("TCA") rider, which is recommended by Staff witness McGarry, versus implementing prospectively an expanded TCA that APS has requested. Consequently, Staff is reserving judgment on this new APS adjustment until an explanation and additional supporting information has been provided. Accordingly, Staff has not reflected it in the determination of the base rate revenue requirement for APS at this time.

STAFF ADJUSTMENTS

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Attachment RCS-2, Schedule C summarizes Staff's recommended net operating income. Schedule C.1 (ACC) presents Staff's recommended adjustments to test year revenues and expenses on an Arizona jurisdictional basis. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. APS' proposed adjusted test year net operating income is $474.356 million, whereas Staff's recommended adjusted net operating income is $498.355 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1. Forensic Investigation of Grant-Funded Projects

Q. Please explain Staff's adjustment for costs related to a forensic investigation of grant-funded projects.

A. Staff Adjustment C-1 removes expense incurred by APS during the 2010 test year related to a forensic investigation conducted for APS into matters pertaining to projects funded with Department of Energy ("DOE") grants. APS' responses to STF 9.2, 9.3, 9.4, 9.7, 9.8, 9.9, 19.21, 20.2, 20.3 and 20.4, many of which contain confidential information, relate to Staff's investigation into such costs. APS' response to STF 9.2 describes that $1 million of such costs had been removed by APS in its original filing, and in that response, APS has also agreed to the removal of the remaining expenses, amounting to $2.129 million, associated with the Integrated Energy System ("IES") project, the Substitute Natural Gas ("SNG") project and the related legal and audit expenses that APS recorded during the 2010 test year. APS' October 26, 2011 update includes an adjustment (APS adjustment no. 34) on APS' Schedule C-2, page 12 to remove the $2.129 million of O&M expense on a total Company basis, and $2.057 million on an ACC jurisdictional basis. Attachment RCS-2, Schedule C-1 reflects the removal of these costs.

Q. Is there a need for a corresponding rate base adjustment related to these DOE grant-funded projects?

A. No. APS' response to STF 9.2 states that APS has not included any costs in rate base associated with the IES or SNG projects.

C-2. General Advertising Expense

Q. How does APS" test year General Advertising Expense compare with 2009?

A. APS" 2010 test year General Advertising Expense in Account 930.1 of $3.549 million exceeds the 2009 recorded amount of $1.808 million by $1.741 million or 96 percent.

Q. Please explain Staff's adjustment to General Advertising Expense.

A. This adjustment decreases APS' General Advertising Expense by approximately $572,000 on an ACC jurisdictional basis to remove general advertising expense that was not specifically related to energy conservation and sustainability, and to provide for a normalized allowance for general advertising expense. In its last rate case, Docket No. E-01345A-11-0224, the Company's response to STF 6.93, had agreed to remove advertising expense that was not specifically related to energy conservation and sustainability. A similar adjustment should be made in the current rate case.

Q. What amount of APS' 2010 general advertising expense was not related to conservation and sustainability?

A. APS' responses to Pre-filed 1.40, APS14082, and to STF 21.1 through 21.5, and to STF 27.10 indicate that $40,688 was incurred for "Breakfast at the Zoo" expense. This was for an employee event, which APS indicates was attended by approximately 2,000 APS employees and their families. APS' response to STF 21.1(p) indicates that the Breakfast at the Zoo charges did not encompass advertising and no advertising copy is available. That APS response also states that this expense should have been recorded to Account 930.2, instead of 930.1. This $40,688 expense for Breakfast at the Zoo is not necessary for the provision of safe and reliable utility service and is not for Commission-approved advertising and has therefore been removed.

Q. Did APS provide copies of the advertisements it ran in 2010?

A. Yes. APS' response to STF 21.1 included copies of advertisements. In general APS' advertisements appear to be consistent with promoting the sustainability objectives. Accordingly, Staff is not proposing to disallow APS' advertising expense related to specific advertisements.

Q. Please explain how you determined a normalized level for general advertising expense.

A. As noted above, APS' 2010 test year General Advertising Expense in Account 930.1 of $3.549 million exceeded the 2009 recorded amount of $1.808 million by $1.741 million or 96 percent. As shown on Attachment RCS-2, Schedule C-2, a three-year average of 2008 through 2010 actual advertising expense is $2.917 million. APS' 2010 general advertising expense, exclusive of the $40,688 Breakfast at the Zoo item, is adjusted to a normalized allowance of $2.917 million. This reduces total Company expense by approximately $631,489 and reduces ACC jurisdictional expense by $572,363.

Q. What is APS' 2011 budget for advertising expense?

A. APS' 2011 advertising budget was stated in response to STF 27.10(j) to be $171,583.33 per month, or $2.059 million for the year. APS' response to STF 27.10(j) at APS14964 states that APS is expected to be on budget by the end of 2011. That response shows that APS was under-budget for YTD September 2009 results.

Q. What explanation did APS provide as to why its 2011 budget of $2.059 million for advertising is so much lower than APS' 2010 actual advertising expense of $3.549 million?

A. APS' response to STF 27.10(h) stated that in 2010, the General Advertising Expense budget included $1.6 million to fund production costs for a new sustainability TV and radio campaign and these ads continued to run in 2011.

Q. How does the normalized annual allowance of $2.917 million for general advertising expense compare with APS' 2011 budget, and with a four-year average including the 2011 budget?

A. The normalized annual allowance of $2.917 million for general advertising expense exceeds APS' 2011 budget by $858,261 or 41.7 percent. A four-year average, 2008 through 2010 actual, and including the 2011 budget, which APS expects to be on by the end of the year, is $2.703 million. The normalized annual allowance of $2.917 million exceeds that four-year average amount by $214,565, or 7.9 percent.

Q. Please summarize the adjustment for General Advertising Expense.

A. As shown on Attachment RCS-2, Schedule C-2, General Advertising Expense should be reduced on an ACC jurisdictional basis by $572,363 to remove an expense for Breakfast at the Zoo and to provide for a normalized annual allowance, based on a three-year average of actual advertising expense for 2008 through 2010.

C-3. Property Tax Expense

Q. Please explain Staff Adjustment C-3.

A. This adjustment uses information provided by APS in its October 26, 2011 Update of its property tax expense adjustment detail, specifically APS14932, page 4 of 5, to adjust pro forma property tax expense to reflect more current information. Attachment RCS-2, Schedule C-3, column A shows the amounts reflected in APS' original filing. Column B shows the updated amounts from APS14932, page 4 of 5. Column C shows the resultant adjustment amounts. As shown on Schedule C-3, line 1, the full cash value of APS' plant has been updated to $7.871 billion (from $7.874 billion in APS' original filing). Also, on Schedule C-3, line 10, the effective property tax rate has been updated from the 9.00 percent used in APS' original filing to the more current rate of 8.96 percent. As shown on

Attachment RCS-2, Schedule C-3, this adjustment reduces property tax expense by $695,000 on a total Company basis and by $584,000 on an ACC jurisdictional basis to reflect more current information on the assessment and effective property tax rate.

C-4. Solar Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-4.

A. This adjustment is shown on Attachment RCS-2, Schedule C-4. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year solar plant and the removal of APS' estimated solar plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-1. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-4, this adjustment decreases ACC jurisdictional depreciation expense by $1.170 million and property tax expense by $131,000, based on differences between Staff's and APS' proposed amounts of post-test-year solar plant additions.

C-5. Fossil Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-5.

A. This adjustment is shown on Attachment RCS-2, Schedule C-5. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year fossil plant and the removal of APS' estimated fossil plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-2. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-5, this adjustment decreases ACC jurisdictional depreciation expense by $637,000 and property tax expense by $146,000, based on differences between Staff's and APS' proposed amounts of post-test-year fossil-fueled generation plant additions.

C-6. Nuclear Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-6.

A. This adjustment is shown on Attachment RCS-2, Schedule C-6. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year nuclear plant and the removal of APS' estimated nuclear plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-3. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-6, this adjustment decreases ACC jurisdictional depreciation expense by $253;000 and property tax expense by $110,000, based on differences between Staff's and APS' proposed amounts of post-test-year nuclear generation plant additions.

C-7. Distribution and General Post-Test-Year Plant Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-7.

A. This adjustment is shown on Attachment RCS-2, Schedule C-7. Column A shows the amounts contained in APS' original filing. Column B shows the Staff adjusted amounts which reflect updates to APS' estimated amount of post test year distribution and general plant and the removal of APS' estimated distribution and general plant additions for April 1 through June 30, 2012, to correspond with Staff's use of post test year plant additions through March 31, 2012, as previously addressed in conjunction with Staff rate base adjustment B-4. Column C shows the adjustment amounts.

As shown on Attachment RCS-2, Schedule C-6, this adjustment decreases ACC jurisdictional depreciation expense by $1.693 million and property tax expense by $971,000 based on differences between Staff's and APS' proposed amounts of post-test-year distribution and general plant additions.

C-8. Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the adjusted rate base to derive a pro forma interest expense deduction that is used in the calculation of test year income expense. After adjustments, Staff's proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Attachment RCS-2, Schedule C-8. This adjustment increases income tax expense by the amount shown on Schedule C-8, line 7 and decreases the Company's achieved operating income by a similar amount.

C-9. Base Cost of Fuel and Purchased Power

Q. What has APS proposed in the current case for the base cost of fuel and purchased power?

A. In its original filing, APS proposed to reduce the base fuel rate from 3.7571 cents per kWh, that was authorized by the Commission in Decision No. 71448, to 3.2415 cents per kWh, based on a projection APS had made of 2012 fuel and purchased power costs, net of an off system sales margin credit.

Q. What was APS' actual base cost of fuel for the 2010 test year?

A. For the test year ending December 31, 2010, APS' actual base cost of fuel and purchased power expense was approximately 3.3486 cents per kWh.[23]

Q. What is the basis for APS' requested base fuel rate?

A. APS' requested base fuel rate is based on a projection of 2012 fuel and purchased power costs made by APS that used March 31, 2011 market prices. Details of APS' proposed 3.2415 cents per kWh are shown at Mr. Ewen's Attachment PME-3. APS' 2012 forecast of fuel expense included assumptions for:

1. Increased electricity sales due to continued growth.
2. Lower commodity market prices for natural gas and power.
3. Higher coal and nuclear prices due to standard contract escalators.
4. Normalized maintenance and unplanned outage times.
5. Cancellation by Salt River Project ("SRP") of a capacity contract with APS.
6. Additional renewable resources consistent with the Company's Renewable Energy Standard ("RES") requirements.

[23] See APS witness Ewen's direct testimony, Attachment PME-4, page 1 of 4.

7. Miscellaneous items, such as broker fees, third-party wheeling expense, and short-term and long-term capacity costs.

Using those assumptions, as shown on APS' Attachment PME-3, page 2 of 4, APS had projected $945.9 million of fuel and purchased power expense for 2012, offset by $16.9 million of off-system sales margin credit, for a net retail fuel cost of $929.0 million. Dividing this cost amount by 28,186 GWh of projected native load sales for 2010 produced the base fuel rate of 3.2415 cents per kWh that APS reflected in its original filing.

Q. **Has APS provided an alternative calculation that includes the impact of APS acquiring Southern California Edison's (SCE) share of Four Corners Units 4 and 5?**

A. Yes. APS' Attachment PME-3, page 3 of 4, shows the Company's proposed base cost of fuel and purchased power, including the effects of acquiring SCE's share of Four Corners Units 4 and 5. This reflects total fuel and purchased power expense of $917.422 million, less off-system margin credits of $20.459 million for a net retail fuel cost of $896.963 million. Dividing the $896.963 million by the 28,658 GWh of projected native load sales for 2010 produces APS' alternative proposed base fuel rate of 3.1298 cents per kWh.

Q. **How does APS' base cost of fuel interact with its Power Supply Adjustor ("PSA") mechanism?**

A. APS' current PSA includes a 90/10 sharing provision for increases in certain fuel and purchased power costs above the base cost of fuel and purchased power. In the Company's filing, APS' annual base rate revenue requirement has been reduced by approximately $144 million (at test year sales levels). Under the 90/10 provision in the PSA, approximately $20.7 million of that decrease would not be passed onto customers.

As explained by APS witness Ewen in his direct testimony at page 4, concerning the impact of the Company's proposed decrease in the base cost of fuel:

> This adjustment reduces the annual base rate revenue requirement by approximately $144 million (at Test Year sales levels). But for the 90/10 sharing arrangement in the PSA, this would amount to no difference in the revenues actually collected from customers. With that sharing arrangement, the impact of the reduction in the base fuel rate amounts to a $21 million net increase in revenues, or about 0.7%. It is important to update the Company's base fuel rate both so that the attendant impact on class rate design can be accounted for and to avoid the 90/10 sharing becoming, in essence, an automatic 10% penalty or reward. Attachment PME-1 shows the results of the proposed adjustments on Test Year revenues. However, as will be discussed later in my testimony, the Company is proposing to remove the 90/10 sharing provision.

Q. Is another Staff witness addressing APS' proposal to remove the 90/10 sharing provision from the PSA?

A. Yes. APS' proposal to remove the 90/10 sharing provision from the PSA is being addressed in the current case by Staff witness Michael McGarry.

Q. How has Staff revised APS' proposed base cost of fuel and purchased power at this time?

A. Staff adjustment C-9 removes APS' pro forma adjustment of $29.810 million related to projected 2012 fuel and purchased power expense and replaced it with a reduction of $39.385 million based on APS' revised forecast of 2012 fuel cost. This adjustment decreases APS' proposed fuel cost by $9.575 million.

Q. What is shown in column F?

A. Column F shows the estimated fuel cost savings that APS projects related to its proposed acquisition of SCE's share of Four Corners Units 4 and 5. As shown on line 10, based on

APS' updated estimates, acquiring SCE's share of Four Corners Units 4 and 5 would reduce fuel and purchased power costs by approximately $31.4 million, versus the amount Staff has used. APS' proposed acquisition of SCE's share of Four Corners Units 4 and 5 is being addressed in another proceeding and has not yet been ruled on by the Commission. Consequently, no incremental fuel savings related to that acquisition are being reflected currently in Staff's (or APS') determination of the base cost of fuel and purchased power.

Q. Might a revision to the base cost of fuel and purchased power be needed if more accurate fuel forecast information for 2012 becomes available at a later point in the processing of the APS rate case?

A. Possibly. Staff is monitoring APS' PSA forecast filings and the concurrent proceeding dealing with APS' request to acquire Four Corners, Units 4 and 5. The impact on base fuel costs resulting from APS' proposed acquisition of SCE's share of Four Corners Units 4 and 5 may need to be revised if that transaction is approved and/or if other significant changes in base fuel costs occur.

C-10. Payroll Expense Adjustment

Q. Please explain the payroll expense adjustment.

A. APS' October 26, 2011 update substantially revised APS' originally filed payroll expense annualization adjustment. The APS update to that adjustment increases O&M expense by $4.855 million on a total Company basis, and by $4.512 million on an ACC jurisdictional basis.

APS' October 26, 2011 update filing, on the Company's revised Schedule C-3, for APS adjustment no. 11, shows an increase to pre-tax O&M expense of $4.512 million on an

ACC jurisdictional basis. In APS' original filing, this same adjustment had decreased O&M expense by $482,000 on an ACC jurisdictional basis. That is a net increase of approximately $4.994 million in jurisdictional O&M expense.

The APS update essentially reflects the impact of two items: (1) correction by APS of errors it discovered in its originally filed adjustment, which increases total Company O&M expense by $3.178 million, and (2) the impact of a new union contract, which increases total Company O&M expense by $2.196 million.

APS indicates that its revised adjustment reflects the impact of a new union contract. APS' workpapers (APS14945, pages 2 and 4 of 10) show a 1.5 percent and 2.5 percent union pay increase for Union 387 for 2011 and 2012, respectively, which cumulatively produce a 4.04 percent increase for the two years combined.[24] That compares to an increase of 1.0 percent only for 2011 that was reflected in APS' originally calculated adjustment. The pay increases resulting from a union contract included in APS' revised payroll annualization adjustment have been accepted by Staff to incorporate the impact of the known and measureable union pay increases into the O&M expenses, based on the Commission's historical practice of reflecting pay increases associated with union contracts.

APS was asked in discovery[25] to explain the other changes which impacted the payroll annualization adjustment. After obtaining and reviewing APS' response to STF 32.1, Staff has also reflected the impact of the error corrections contained in APS' revised payroll annualization adjustment. APS' response to STF 32.1 explains the corrections to the original APS payroll annualization adjustment, which includes revisions to 2010 recorded amounts and March 2011 annualized amounts. APS has indicated that its

[24] 1.015 x 1.025 = 1.0404.
[25] Staff set 32, issued November 7, 2011.

original adjustment had mistakenly included in test year base pay amounts related to the selling of paid time off and paid earned and accrued vacation, which had overstated the test year base pay and related payroll tax expense, and understated the amount of the payroll annualization adjustment.

In summary, as shown on Attachment RCS-2, Schedule C-10, this adjustment increases jurisdictional O&M expense by $4.994 million.

C-11. Depreciation Expense – New Depreciation Rates for Meters

Q. Please explain Staff Adjustment C-11.

A. This adjustment reflects the rejection of APS' proposed new depreciation rate proposal for Account 370.01, electronic meters, and Account 370.03, AMI meters. APS proposes to increase the annual depreciation for electronic meters, from $2.289 million at the currently authorized depreciation rate of 3.68 percent, to $3.863 million, for a proposed new depreciation rate of 6.21 percent, per its 2011 Depreciation Study.[26] That is an increase of $1.574 million, or 68.7 percent.

For AMI meters, APS proposes to increase the annual depreciation from $4.497 million at the currently authorized depreciation rate of 3.82 percent, to $7.687 million for a proposed new depreciation rate of 6.53 percent, per its 2011 Depreciation Study. That is an increase of $3.190 million, or 70.9 percent.

[26] See Exhibit REW-2, pages 18 and 26. The annual depreciation accrual amounts are based on December 31, 2010 plant.

Q. How do the depreciable lives reflected in the currently authorized depreciation rates for these accounts compare with APS' proposal for new depreciation rates?

A. The currently authorized depreciation rates for these accounts are based upon a 26 year average service life for each type of meters. In contrast, APS' proposal for new depreciation rates has reflected average service lives of only 15 years for each type of meters.

Q. Has APS discontinued the purchase and installation of electronic meters?

A. No. Electronic meters are not obsolete and APS has added significant amounts of new plant to Account 370.01 in recent years.

Q. What was the net plant balance at December 31, 2010?

A. As of December 31, 2010, the end of the test year, the plant balance, accumulated depreciation, and net plant amounts were as follows:

Description	Original Plant Cost @ 12/31/2010	Accumulated Depreciation at 12/31/2010	Net Plant Balance
	(E)	(F)	(G)
Using Recorded Depreciation Reserve			
Electronic Meters - Plant Account 370 01	$ 62,207,543	$ (19,681,616)	$ 42,525,927

Q. What significant additions has APS made to the electronic meters account in recent years?

A. As examples, APS added $11.936 million to this account in 2007 and another $11.953 million had been added in 2005.[27]

[27] See APS' response to STF 12.27(d) in APS' last rate case, Docket No. E-01345A-08-0172. A copy of that response is included in Attachment RCS-3, attached to my testimony.

Q. Has APS projected further substantial additions to Account 370.01 in years beyond the 2007 test year used in its last rate case?

A. Yes. APS' response to STF 12.27(h) in Docket No. E-01345A-08-0172 stated that APS estimated meter additions for Account 370.01 of $12.5 million in 2008, $8.9 million in 2009 and $4.2 million in 2010.

Q. What depreciation rates had APS been using for Account 370.01?

A. The depreciation rates that APS has used for these accounts from 1998 through the present were identified in the response to STF 17.7(h) in Docket E-01345A-08-0172[28] as follows:

Account 370.01, Electronic Meters	Depreciation Rate
1998 to March 2005:	4.54%
April 2005 to June 2007:	3.61%
July 2007 to present:	3.68%

Q. How does APS' existing depreciation rate for electronic meters, Account 370.01, compare with the depreciation being used by other Arizona electric utilities?

A. The present depreciation rate used by APS for Account 370.01, electronic meters, is 3.68 percent. Tucson Electric Power Company ("TEP") uses a depreciation rate of 2.99 percent for Account 370.00, Meters.[29] UNS Electric, Inc. ("UNSE") used a rate of 3.11 percent for Account 370.00, Meters.[30] TEP and UNSE do not break out their investment in Meters into separate sub-accounts. APS' existing 3.68 percent depreciation rate for electronic meters is higher (i.e., produces more depreciation in each year) than the recently approved revised rates being used by TEP and UNSE in Docket Nos. E-01933A-07-0402

[28] A copy of that response is included in Attachment RCS-3.
[29] See, e.g., Docket No. E-01933A-07-0402, direct testimony of TEP witness, Dr. Kimbugwe Kateregga, Exhibit KAK-1, 2007 Depreciation Rate Study, page 60.
[30] See, e.g., Docket No. E-04204A-06-0783, direct testimony of UNSE witness, Dr. Ronald White, Exhibit REW-2, 2006 Depreciation Rate Revenue, page 15.

and E-04204A-06-0783, respectively. UNSE also filed a technical update of its depreciation rates in Docket No. E-04204A-09-0206, sponsored by Dr. White. UNSE's depreciation rates in that case were accepted and reflected a 3.01 percent depreciation rate for meters. The 3.01 percent rate was a decrease from the previous 3.11 percent depreciation rate used by UNSE for meters. Page 18 of Dr. White's depreciation study for UNSE in Docket No. E-04204A-09-0206[31] shows that the average service life for UNSE's meters (Account 370.00) at the previous and revised depreciation rates was 34 years. The remaining life for UNSE's meters account increased from 24.14 years to 25.56 years.

Q. APS is proposing to substantially increase the annual depreciation expense for Account 370.01, electronic meters. You mentioned the depreciation rates for Meters, Account 370, that were authorized for TEP and UNSE in their most recent rate cases. How were the then-existing depreciation rates for Meters changed in those TEP and UNSE rate cases?

A. In Docket No. E-01933A-07-0402, TEP's depreciation rate for Account 370, Meters, was <u>reduced</u> from 3.79 percent to 2.99 percent.[32] In Docket No. E-04204A-06-0783, UNSE's depreciation rate for Meters was <u>reduced</u> from 3.25 percent to 3.11 percent. These reductions in the depreciation rate for Meters for the other two Arizona electric utilities contrast with APS' proposal for a substantial increase. In Docket No. E-04204A-09-0206, UNSE's depreciation rate for Meters was <u>reduced</u> from 3.11 percent to 3.01 percent.

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[31] A copy of selected pages from Dr. White's Attachment REW-2, 2009 Technical Update, for UNS Electric in E-04204A-09-0206, relating to the average service lives, remaining life, and depreciation rates for UNSE meters is included in Attachment RCS-3 to my testimony.

[32] See, e.g., Docket No. E-01933A-07-0402, direct testimony of TEP witness, Dr. Kimbugwe Kateregga, Exhibit KAK-1, 2007 Depreciation Rate Study, page 60. Cost of removal for distribution plant was broken out as a separate depreciation rate component in the approved depreciation rates. TEP's existing depreciation rate for Meters prior to Docket No. E-01933A-07-0402 had included a provision for negative net salvage.

Q. What other concerns does Staff have regarding APS proposed replacement of electronic meters?

A. APS has not demonstrated that it is economical, cost-effective or even prudent to purchase and then replace electronic meters within only a few years of their initial installation. Moreover, electronic meters that are new or only a few years old should have significant salvage value, yet APS has reflected salvage value of only 0.03 percent[33] (i.e., only 3 cents of value for every $1 invested) for electronic meters in its proposed depreciation rates.

Q. How should APS' proposed depreciation for Account 370.01 be adjusted?

A. The existing depreciation rate of 3.68% should be applied. As shown on Attachment RCS-2, Schedule C-11, this produces annual depreciation of $2.289 million. APS' proposal for $3.863 million of depreciation expense for this account should be rejected. The jurisdictional adjustment reduces depreciation expense by $1.564 million.

Q. What did APS state in its last depreciation rate study concerning the appropriate depreciation period for AMI meters?

A. Page 4 of APS' 2008 Depreciation Rate Study[34] stated that:

> Amortization accounting is also recommended for Account 370.01 (Meters-Electronic) and Account 370.02 (Meters-Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5-year amortization period is recommended for Accounts 370.01 and 370.02. **The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology.** Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function. (Emphasis supplied.)

[33] See, e.g., Exhibit REW-2, at page 18.
[34] See Attachment REW-1 to APS witness Dr. White's direct testimony in Docket No. E-01345A-08-0172

Q. Does that same situation exist in the current APS rate case?

A. Yes. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. The 26 year average service life period that has traditionally been applied to meter investment should continue for AMI meters.

Q. How should APS' proposed depreciation of AMI meters be adjusted?

A. As shown on Attachment RCS-2, Schedule C-11, the existing authorized depreciation rate of 3.82 percent should continue to be applied. This reduces APS' requested depreciation expense for Account 370.3, AMI meters, by $3.171 million on an ACC jurisdictional basis.

Q. Is another Staff witness addressing the useful lives of electronic and AMI meters from an engineering perspective?

A. Yes. Staff witness Michael Lewis is addressing the useful lives of electronic and AMI meters from an engineering perspective. He has concluded that there is no reason from an engineering perspective why AMI meters should not last as long as older meters.

Q. Should the issue of APS' meter replacement program and its impact on the service lives of investment in Account 370.01, electronic meters, and 370.03, AMI meters, be reviewed in APS' next rate case?

A. Yes. The issue of APS' meter replacement program and its impact on Account 370.01, electronic meters, should be reviewed in APS' next rate case. APS should be directed to present evidence demonstrating that its continuing purchase and installation of tens of millions of dollars of electronic meters in conjunction with its apparent plans to then replace them within a few years with more advanced "smart meters" is economical, cost-effective and prudent. APS should also be directed to present updated information on retirement experience necessary to re-evaluate the depreciation rate for Accounts 370.01, electronic meters, and 370.03, AMI meters, at that time.[35] In that case, APS should also present updated information concerning the useful life of AMI meters.

C-12. Prospective Amortization of 2010 Severance Costs

Q. Please explain Staff Adjustment C-12.

A. This adjustment is shown on Attachment RCS-2, Schedule C-12, and removes the $3.366 million total Company and $3.128 million ACC jurisdictional expense requested by APS for amortization over a three-year period of the $10.099 million cost of APS' 2010 non-voluntary severance program.[36] As explained in the response to STF 25.6(d), APS has requested that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the test year, for one year of an APS-proposed three-year amortization of such severance costs.

Staff has removed this prospective amortization because the first year savings identified by APS of $23.446 million in total, and approximately $11.5 million of APS O&M expense savings and $3.9 million of APS capital savings, are sufficient to have fully amortized the $10.099 million severance cost during the first full annual period during which such savings were realized. Staff's analysis indicates that a one-year amortization from April 2011 through March 2012 is sufficient to fully amortize such cost against the realized savings. Consequently, no remaining unamortized balance should remain by July 1, 2012, the approximate date on which new base rates for APS from the current APS rate case would become effective. The APS request for $3.366 million of prospective

[35] This need not take the form of a complete new depreciation rate study, but could be in the form of a Technical Update, focusing on Account 370 (and any other accounts that had experienced significant changes).
[36] These amounts are confirmed in APS' response to STF 25.8.

amortization of this cost is unwarranted because the savings realized by APS will have enabled the full amortization of the severance costs prior to the effective date of new rates in the current APS base rate case.

Q. Did APS file a request for an accounting deferral or establish a regulatory asset related to the $10.099 million of 2010 non-voluntary severance program cost?

A. No. As explained in the Company's response to STF 25.5(k), APS did not file a request for accounting deferrals or establish a regulatory asset related to the $10.099 million. APS has requested that the $10.099 million be amortized over a 3-year period to match the cost against the benefit.

Q. When did APS experience the benefit of the 2010 non-voluntary severance program?

A. APS began experiencing the benefit of the 2010 non-voluntary severance program as its work force was down-sized during the period January 2010 through March 2011. APS' response to STF 25.5(a) identifies the monthly work force changes and states that during the period January 2010 through March 2011 the total number of APS/PNW regular employees was reduced by a net 259 employees, as a combination of voluntary employee terminations and non-voluntary terminations, offset by employee new hires.

Q. What amount of total first year savings for the severance program has APS identified?

A. APS' response to STF 25.5(b) has identified first year savings of $23.446 million.

Q. What calendar period has APS identified as the "first year" in which APS is realizing those savings?

A. APS' response to STF 25.5(d) states that the first full year of savings is for the 12 month period April 2011 through March 2012.

Q. How much O&M expense and capital cost savings attributable to the severance is being realized by APS during that "first year" period of April 2011 through March 2012?

A. APS' response to STF 25.5(g) indicates that of the $23.446 million total savings, approximately $11.5 million relates to APS O&M savings and $3.9 million relates to APS capital savings, with the remainder relating to amounts billed to participants in jointly owned facilities.

Q. What does Staff propose?

A. Staff proposes that the amortization of the $10.099 million 2010 non-voluntary severance program cost commence when APS began realizing the savings. Coordinating the amortization of the 2010 severance cost with the realization by APS of such savings results in a conclusion that there is no remaining unamortized amount left when new base rates for APS in the current rate case would take effect. The $11.5 million APS O&M savings and $3.9 million APS capital savings identified by the Company as being realized for the first year, April 2011 through March 2012, are sufficient to fully amortize the $10.099 million cost by March 2012, if not sooner, indicating that there should be no remaining unamortized cost existing by July 1, 2012 when new base rates for APS have been anticipated to be in effect. Consequently, the prospective $3.366 million amortization proposed by APS, which is $3.128 million on an ACC jurisdictional basis, has been removed from test year operating expenses, as shown on Attachment RCS-2, Schedule C-12.

C-13. Directors and Officers' Liability Insurance Expense

Q. Please explain Staff Adjustment C-13.

A. This adjustment is shown on Attachment RCS-2, Schedule C-13 and removes one-half of the Directors and Officers' Liability Insurance expense and reduces jurisdictional test year O&M expense by $550,000. The removal of one-half of this expense reflects an equal (i.e., 50/50) sharing of the cost for this insurance between shareholders and ratepayers.

Q. Why should the cost of the D&O insurance expense be shared between shareholders and ratepayers?

A. This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as APS' parent company, Pinnacle West. Thus, it helps protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit from this because having such insurance improves the ability of the publicly traded parent corporation to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O Insurance.

Q. Was this adjustment made in APS' last rate case?

A. To my knowledge it was not.

Q. Did Staff recommend a similar adjustment in Southwest Gas' most recent Arizona rate case?

A. Yes. A similar adjustment was also made in Southwest Gas' most recent Nevada rate case, Nevada PSC Docket No. 09-04003, and adopted by the Nevada Commission in an order dated October 29, 2009. Southwest's D&O Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same Southwest D&O Insurance expense that was recently disallowed in Nevada was being allocated to Arizona, and was adjusted for 50/50 sharing by Staff in SWG's most recent Arizona rate case, Docket No. G-01151A-10-0458.[37]

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in Southwest Gas' last rate case, at page 47, paragraph 157, cites two states (Arkansas and California) that have required a sharing of D&O Liability Insurance Expense between ratepayers and shareholders on a 50-50 basis.[38] We are aware that at least two other commissions (Connecticut and Florida) have made adjustments for a ratepayer and shareholder sharing of D&O Insurance expense. Connecticut has required shareholders to share a portion of the cost of D&O Insurance expense, with the shareholder portion varying from 50 percent to 75 percent in different cases.

[37] Southwest Gas' most recent rate case resulted in a settlement being reached by most of the parties to that case, which incorporated this Staff adjustment; however, a final decision has not yet been issued by the Commission in that case.

[38] To date, we have not located the Arkansas and California commission orders which required that sharing.

Q. Have you included an attachment with excerpts from the orders of which you are aware which have made such findings concerning sharing of D&O Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders that we have currently located.

Q. Please summarize the adjustment to expense for D&O Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-13, APS' proposed test year expense for D&O Insurance of $1.170 million should be reduced by $585,000 to reflect an allocation of 50 percent of this expense to shareholders. The ACC jurisdictional adjustment to expense is a reduction of $550,000.

Q. Is there a related adjustment to rate base?

A. No. APS' response to STF 21.6(a) indicated that it expenses D&O Insurance as incurred and did not include a rate base item for prepaid D&O insurance.

C-14. Annual Incentive Compensation

Q. Please explain Staff Adjustment C-14.

A. This adjustment is shown on Attachment RCS-2, Schedule C-14. The adjustment first normalizes the test year annual incentive compensation expense amount based on an average of the last three years, 2008 through 2010. In comparison with the average, the 2010 test year amount was significantly higher. This adjustment then removes 50% of a normalized level of expense related to APS' annual incentive compensation to reflect the sharing of that expense between shareholders and ratepayers.

Q. Please explain the reason for removing 50 percent of the normalized incentive compensation expense.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals. Moreover, there is no assurance that the award levels included in the Company's proposed or Staff's normalized expense (before sharing) will be repeated in future years.

Q. What is the result of Staff adjustment C-14?

A. Test year expense for incentive compensation proposed by APS is reduced by $20.370 million on a total Company basis and by $18.930 million on an ACC jurisdictional basis.

Q. What was APS' incentive compensation expense in the 2010 test year, and how did that compare with prior years?

A. The table below shows the amounts of incentive compensation charged to O&M for each year 2005 through 2007, which were provided in APS' response to STF 19.17 from APS' last rate case and for years 2008 through 2010 as provided in APS' response to STF 22.2 in the current case:

Year	Total Company	ACC Jurisdictional
2005	$21.752 million	$20.522 million
2006	$21.005 million	$19.842 million
2007	$28.342 million	$26.470 million
[BEGIN CONFIDENTIAL]		
[redacted]	[redacted]	[redacted]
[END CONFIDENTIAL]		

The 2010 test year amount is significantly higher than the comparable amounts from prior years.

Q. How much of APS' 2010 test year incentive compensation expense was for Officers and Senior Management?

A. It appears that the officers' portion of test year incentive compensation expense was approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. Has APS identified the amount of incentive compensation related to front line and non-senior management?

A. APS has identified that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is for front line and non-senior management.

Q. Please briefly discuss the key provisions of APS' Annual Incentive Plan.

A. APS' 2011 Annual Incentive Award Program (AIA) was provided in response to STF 1.16 as CONFIDENTIAL APS14212. The 2011 AIA is comprised of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[39] Per APS' response to STF 20.8, APS14893.

[redacted] [END CONFIDENTIAL]

Q. You stated that the AIA is comprised of three components. Please discuss the [BEGIN CONFIDENTIAL] [redacted] [redacted] [redacted] [END CONFIDENTIAL]

A. Per APS14212, page 2 of 17:

> **[BEGIN CONFIDENTIAL]**
>
> [redacted]
>
> **[END CONFIDENTIAL]**

Q. Please discuss the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of APS' 2011 AIA.

A. The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is described in APS14212, page 2 of 17, as follows:

> **[BEGIN CONFIDENTIAL]**
>
> [redacted]

[redacted]

[END CONFIDENTIAL]

Q. How does the third component, the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] affect the calculated total incentive award?

A. It doesn't. The achievement of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** goals determines the total calculated incentive award, and the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** affects the amounts received by individual employees.

Q. Has APS listed the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] on which the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] of the AIA is predicated?

A. Yes, those items are listed on APS14212, pages 4-7 of 17, which is reproduced in Attachment RCS-4.

Q. Do APS' shareholders and customers both benefit from its AIA goals?

A. Yes. As noted above, the primary purpose of the APS performance portion of the AIA is to emphasize the importance of the Company's earnings. For an AIA award to occur, APS' earnings must exceed a threshold level. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** measures include a variety of measures, including shareholder value-oriented goals and customer satisfaction, indicating that there are benefits to both shareholders and customers from the achievement of AIA Business Unit goals that result in the payment of incentive compensation.

Q. **Was an equal sharing of APS' cash-based incentive compensation expense required in APS' last litigated rate case?**

A. No. In APS' last litigated base rate case, Docket No. E-01345A-05-0816, only stock-based compensation was removed. However, in APS' last base rate case, Docket No. E-01345A-08-0172, Staff made an adjustment to share on a 50/50 basis between shareholders and ratepayers APS' cash-based incentive compensation expense. That Staff adjustment was incorporated into the development of the allowed revenue requirement for APS in that proceeding.

Q. **Was an equal sharing of incentive compensation expense ordered in Commission decisions in other rate cases involving Arizona utilities?**

A. Yes. In Decision No. 70011 (November 27, 2007), in the UNS Gas, Inc. rate case, Docket No. G-04204A-06-0463, the Commission stated on page 27 that:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

In Decision No. 70360 (May 27, 2008), in a UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21 that:

> Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Gas case are virtually identical to those

> presented in this case, we see no reason to deviate from that recent decision.

In Decision No. 68487 (February 23, 2006), in a Southwest Gas Company rate case, Docket No. G-01551A-04-0876, the Commission stated at page 18 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers.

In Decision No. 70665 (December 24, 2008) in a Southwest Gas rate case, Docket No. G-01551A-07-0504, the Commission stated at page 16:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
>> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

[3]See UNS Gas, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.

[4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

In Decision No. 71623 (April 14, 2010) in a UNS Gas rate case, Docket No. G-04204A-08-0571, the Commission stated at 30-31:

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provides a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program in comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that approximately 40 percent of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.
>
> Therefore, consistent with the recent cases cited above, we will adopt the recommendation of Staff and RUCO on this issue.

In Decision No. 71914 (September 30, 2010), in a UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at pages 28-29 that:

> UNSE ... argues that its PEP is very similar to Arizona Public Service Company's (APS) cash-based incentive compensation plan which the Commission allowed recovery of in Decision No. 69663 (June 28, 2007).
>
> Staff and RUCO recommended that the Commission disallow 50 percent of the PEP costs, consistent with the Commission's previous treatment of this expense. ...

> We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.
>
> Therefore, consistent with the recent cases cited above, we will adopt the recommendation of Staff and RUCO on this issue ....

In Decision No. 71914, the Commission also disallowed UNSE's expense for stock-based compensation.

Q. Please summarize Staff's recommendation concerning APS' annual incentive plan compensation expense.

A. Staff recommends a 50 percent sharing of normalized incentive compensation expense between shareholders and ratepayers. As shown on Attachment RCS-2, Schedule C-14, this results in a reduction to test year expense of $20.37 million on a total Company basis and $18.930 million on an ACC jurisdictional basis.

C-15. Fossil Non-Plant Maintenance Expense

Q. Please explain the adjustment for Fossil Non-Plant Maintenance Expense.

A. As part of its adjustment to normalize fossil plant maintenance expense, using a six-year average of 2005 through 2010, APS had included an adjustment to increase O&M expense by $882,000 for fossil non-plant maintenance. This is maintenance that is not associated with a specific fossil-fuel fired generating plant. APS' proposed adjustment represents a 660 percent increase over the 2010 recorded amount of $116,000:

Fossil Non-Plant Maintenance Expense		
		Percent Increase
Year	Amount ($000)	Over 2010
2005	$ 2,246	1836%
2006	$ 999	761%
2007	$ 660	469%
2008	$ 495	327%
2009	$ 773	566%
2010	$ 116	0%
Averages:		
Six Years	$ 882	660%
Five Years	$ 609	425%

The 2005 amount used in APS' average for that of $2.246 million does not appear to be representative of current or ongoing experience, and includes costs that are not typically incurred. APS' response to STF 25.21 states, for example, that:

> Year 2005 was $900,000 higher than other years because of $657,000 in incentive charged in that year plus a higher than average payroll accrual charged that year to department 9960 of $235,000 compared to the six year average of $55,000.

The Staff adjustment shown on Attachment RCS-2, Schedule C-15, page 1, uses a five-year average of 2006 through 2010 for this, for a normalized allowance of $609,000. That reduces APS' requested amount by $273,000 in total and by $266,000 on an ACC jurisdictional basis.

Fossil Plant Maintenance Expense for Four Corners Plant

Q. Does Staff have any other concerns about APS' requested amount for fossil plant maintenance expense?

A. Yes. As shown on Attachment RCS-2, Schedule C-15, page 2, APS has requested an annual normalized O&M expense allowance of $22.759 million for maintenance on the Four Corners plant, including $16.775 million for Four Corners Units 1-3. The $16.775 million Four Corners Units 1-3 maintenance expense amount includes $8.002 million for plant overhauls and $8.773 million for routine maintenance. APS has treated Four Corners Units 1-3 in other respects in its filing as units that are to be retired by the end of 2012.[40] Since APS has represented that Four Corners Units 1-3 may be retired by the end of 2012, Staff is concerned about the $16.775 million annual maintenance expense amount that APS has requested for Four Corners Units 1-3 in terms of whether that expense is representative of ongoing operations.

Q. Does the normal overhaul and maintenance expense typically cease after a fossil unit is retired?

A. Yes. APS' response to STF 25.22(f), for example, states that:

> The normal overhaul and ongoing maintenance cycles would cease after a fossil unit has been retired. However, costs will be incurred after a plant ceases operation in order to perform activities to secure the unit in a safe condition until dismantlement and decommissioning.

Q. Are APS' maintenance costs on the Four Corners plant a subject that is pending before the Commission in another docket?

A. Yes. As explained in APS' response to STF 25.22(e):

[40] See, e.g., APS' response to data request STF 27.11, and APS' depreciation rate study, sponsored by APS witness Ronald White, and the Direct Testimony of Dr. White at page 10.

APS' deferral order proposed in Docket No. E-01345A-10-0474, would net any reduced costs of Units 1-3 with the acquisition of SCE's share of Units 4-5, thus providing customers the benefit of any cost offsets. Also, as stated in that Docket, Units 1-3 could continue running past the acquisition date to (1) allow for a transition period and (2) if favorable market conditions exist, APS could sell the output as off-system sales, crediting margins to customers through the PSA.

Q. Has Staff made any pro forma adjustment to address Four Corners maintenance expense at this time?

A. No. Given the uncertain status of the continued operation of Four Corners, particularly Units 1-3, and the related issues that are being addressed in Docket No. E-01345A-10-0474, including the accounting deferral sought by APS in that proceeding, Staff is not making any pro forma adjustment to address Four Corners maintenance expense at this time.

C-17. Edison Electric Institute Dues

Q. Please explain the adjustment for Edison Electric Institute ("EEI") Dues.

A. This adjustment is shown on Attachment RCS-2, Schedule C-17 and reduces test year expense by $230,252 on a total Company basis and $216,273 on an ACC jurisdictional basis.

Q. How does your adjustment for Edison Electric Institute Dues compare with APS' proposed treatment of such dues?

A. It reflects the removal of 49.93 percent of EEI core dues, or $338,830 versus APS' adjustment to only remove the lobbying portion, or $108,578, of such EEI core dues. APS indicated in its response to STF 1.36 on the workpaper designated APS14209, page 4 of 4, that it removed 16 percent of the EEI core dues (apparently only the direct lobbying portion).

Q. How did you determine the portion of EEI core dues that should not be charged to ratepayers?

A. I obtained a classification by NARUC category for EEI Core Dues activities for the year ended December 31, 2005. This is shown on Schedule C-17, page 2. EEI Core Dues relating to the following activities should be excluded from rates:

- Legislative Advocacy
- Regulatory Advocacy
- Advertising
- Marketing
- Public Relations

The sum of EEI Core Dues activities for these NARUC categories totals 49.93 percent, as shown on Schedule C-17, page 2.

Q. Why is 2005 EEI information being used as the basis for the disallowance percentage?

A. In STF set 22, APS was asked to provide current information, but did not provide it. STF 22.5 specifically asked APS to provide the following information:

> a) Please provide the EEI budget for each year 2008, 2009, 2010 and 2011.
>
> b) Please provide the EEI financial statements for each year 2008, 2009, 2010 and 2011.
>
> c) Does APS have any information breaking out EEI core dues activities by NARUC operating expense category, i.e., legislative advocacy; legislative policy research; regulatory advocacy; regulatory policy research; advertising; marketing; utility operations and engineering; financial, legal planning and customer service;

> public relations; and other? If not, explain fully why not. If so, please provide the most current information APS has.

APS' response stated that:

> a) APS does not receive copies of EEI's budget.
>
> b) APS does not receive copies of EEI's financial statements.
>
> c) EEI does not prepare a schedule of expenses by NARUC Category. Instead EEI provides a copy of a letter that identifies the percent of dues spent on legislative advocacy, which APS previously provided in response to Staff 1.36 as ASP14209.

As a result of APS' failure to provide the information requested in STF 22.5, Staff has concluded that APS has failed to justify inclusion in rates of any amount of EEI dues for regular activities above the 49.93 percent that is shown on Schedule C-13, page 2, and was the basis for Staff's recommended disallowance of EEI core dues in APS' last rate case, Docket No. E-01345A-08-0172.

Q. What is the purpose of the NARUC-designated categorization of EEI expenditures?

A. The purpose of the NARUC-designated categorization of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities. Certain expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit. The NARUC-designated categories of EEI expenditures are thus intended to be helpful to state utility regulatory commissions.

Q. Was this same percentage for the EEI core dues disallowance used in any other electric utility rate cases of which you are aware?

A. Yes. The Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case, in Order No. 10 (6/15/07) adopted a similar adjustment to reflect the disallowance of 49.93 percent of EEI core dues.

In addition, in a proceeding before the Arizona Corporation Commission in Docket No. E-04204A-06-0783, a UNS Electric, Inc., rate case, in Order No. 70360 dated May 27, 2008, the Commission stated in part:

> We agree with Mr. Smith's assessment that the portions of the EEI dues related to legislative and regulatory advocacy, advertising, marketing and public relations should not be included in recoverable test year expenses in this case. We believe Staff raises a valid point regarding the nature of EEI core dues, and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of service to UNSE customers. We therefore adopt Staff's position on this issue.

This 49.93 percent disallowance of EEI core dues corresponds to the above-identified activity categories.

THE COMPANY'S PROPOSED DEPRECIATION RATES

Depreciation Terminology and Concepts

Q. Before discussing specific issues associated with APS' proposed depreciation rates, could you please provide your understanding of some basic depreciation terminology?

A. Yes, of course.

Q. What Commission rules address the treatment of depreciation?

A. The Commission's rules at R14-02-102 address the treatment of depreciation. The current version of the rules appear to have been adopted effective April 9, 1992.

Q. What is depreciation?

A. The Commission's rules at R14-2-102(A)(3) define "depreciation" as "an accounting process which will permit the recovery of the original cost of an asset less its net salvage over the service life."

Q. What is net salvage?

A. The Commission's rules at R14-2-102(A)(5) define "net salvage" as "the salvage value of property less the cost of removal."

Q. What is "salvage value"?

A. The Commission's rules at R14-2-102(A)(5) define "salvage value" as:

> the amount received for assets retired, less any expenses incurred in selling or preparing the assets for sale; of if retained, the amount at which the material recoverable is chargeable to materials and supplies, or other appropriate accounts.

Q. What is the "cost of removal"?

A. The Commission's rules at R14-2-102(A)(5) define the "cost of removal" as "the cost of demolishing, dismantling, removing, tearing down, or abandoning of physical assets, including the cost of transportation and handling incidental thereto."

Q. What is depreciation expense?

A. Depreciation expense is a charge to operating expense to reflect the recovery of depreciable utility plant. Depreciation rates are applied to a utility's depreciable utility plant to determine the amount of depreciation expense. Public utility depreciation expense is typically straight-line over the service life which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant and equipment is in service.[41]

Q. What is depreciable utility plant?

A. Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Plant additions, retirements and balances are maintained by plant account. An annual addition is the original cost of plant added to the account during the year. A retirement is recorded in the plant account by removing the original cost of a prior addition when such plant is removed from service. The plant balance is what is left at the end of an accounting period after accounting for additions and retirements.

Q. How is the annual depreciation expense calculated?

A. Annual depreciation expense, called an accrual, is calculated by applying a depreciation rate to plant balances.

Q. Is the depreciation accrual a cash expense?

A. No. Depreciation is considered a <u>non-cash</u> expense.

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[41] National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices, August, 1996. ("NARUC Depreciation Manual"), p. 321. Also, Commission Rule R14-2-102, which defines "service life" as "the period between the date an asset is first devoted to public service and the date of its retirement from service."

Q. Please explain the distinction between a cash and non-cash expense.

A. Depreciation expense is considered a non-cash accrual. This contrasts with payroll expense, for example, which involves the current outlay of cash. Depreciation expense does not involve a specific payment during the test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and is simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service. The following accounting entries illustrate the difference:

Account	Description	Amount Dr. (Cr.)
403	Depreciation Expense	$ 1,000
108	Accumulated Depreciation	$ (1,000)
	To record depreciation	

various	Payroll Expense	$ 1,000
131	Cash	$ (1,000)
	To record payroll expense	

Q. What is the Accumulated Depreciation account?

A. Accumulated Depreciation, Account 108 in the USOA, is a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. From a regulatory perspective, Accumulated Depreciation can be considered a measure of the depreciation recovered from ratepayers. Commission Rule R14-2-102 defines "accumulated depreciation" as "the sum of the annual provision for depreciation from the time that the asset is first devoted to public service."

Q. How does depreciation expense impact a utility's revenue requirement?

A. Annual depreciation expense is a cost that is included in a public utility's revenue requirement. Because public utilities tend to be capital intensive, depreciation expense can be a significant component of the utility's revenue requirement.

Q. What is the objective of depreciation expense?

A. From a regulatory perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances. Additionally, many state regulatory commissions, including the ACC, have allowed utilities to recover through the commission-authorized depreciation rates, the utility's estimated future cost of removal, which is part of the net salvage component of the depreciation rates.

Q. Please explain the concept of remaining life depreciation.

A. The remaining life technique incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather that the whole life of the asset.

Q. Can you provide a similar illustration of how accumulated depreciation is incorporated into the numerator of the basic depreciation calculation?

A. If a 10-year asset is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 30% of the original cost because the 10% depreciation rate would have been applied for three years (3 x 10% = 30%). The remaining life depreciation rate would then be 10%, calculated as follows:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment and a 10-Year Life
Depreciation Rate: [100% - 30%] / [10 - 3 Years] = 10% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation
3		$ (300,000)
4	$ 100,000	$ (400,000)
5	$ 100,000	$ (500,000)
6	$ 100,000	$ (600,000)
7	$ 100,000	$ (700,000)
8	$ 100,000	$ (800,000)
9	$ 100,000	$ (900,000)
10	$ 100,000	$ (1,000,000)
TOTAL	$ 700,000	

Under an example with an assumed 55% negative net salvage, and a 7-year remaining life, the results would be a 15.5% depreciation rate, as shown below:

Straight-Line Remaining-Life Depreciation Rate
Assuming $1 Million Investment, a 10-Year Life
And Negative Net Salvage of 55%
Depreciation Rate: [(100% - (-55%)) - (3 x 15.5%)] / [10 - 3 Years] = 15.5% Per Year
Depreciation Rate: [(108.5%)] / [7 Years] = 15.5% Per Year

Year	Annual Depreciation Expense	End-of-Year Accumulated Depreciation	Annual Negative Net Salvage Charge	FAS 143 Regulatory Liability
3		$ (300,000)		$ (165,000)
4	$ 100,000	$ (400,000)	$ 55,000	$ (220,000)
5	$ 100,000	$ (500,000)	$ 55,000	$ (275,000)
6	$ 100,000	$ (600,000)	$ 55,000	$ (330,000)
7	$ 100,000	$ (700,000)	$ 55,000	$ (385,000)
8	$ 100,000	$ (800,000)	$ 55,000	$ (440,000)
9	$ 100,000	$ (900,000)	$ 55,000	$ (495,000)
10	$ 100,000	$ (1,000,000)	$ 55,000	$ (550,000)
TOTAL	$ 700,000		$ 385,000	

APS' Proposed New Depreciation Rates

Q. How has APS requested new depreciation rates in the current case?

A. APS witness Ronald White sponsors a 2011 Depreciation Rate Study for APS, which is presented in Attachment REW-2 to his direct testimony.

Q. How were APS' depreciation rates modified in its last rate case, Docket No. E-01345A-08-0172?

A. In its last rate case, APS' depreciation rates were modified in a depreciation study sponsored by APS witness Dr. White. In that case, Staff concluded that, with the exception of the Company's proposed depreciation rates for account 370.01, electronic meters, the depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. Additionally, APS applied for and was granted an operating license extension for the Palo Verde Nuclear Generating Station. The estimated impact of that license extension on Palo Verde depreciation rates was addressed in the Settlement Agreement in Docket No. E-01345A-08-0172.[42]

Q. Please discuss the Company's proposed depreciation rates and how they were derived.

A. The new depreciation rates proposed by APS are summarized in Company witness Dr. White's testimony and are shown in detail in his exhibit, Attachment REW-2. APS' new depreciation rates are the result of a depreciation study prepared by Dr. White's firm, Foster Associates, Inc., entitled "2011 Depreciation Rate Study" which is Attachment REW-2. With the exception of selected general support asset categories for which amortization accounting has been approved, the Company's proposed rates were developed using a depreciation system composed of the straight-line method, vintage group procedure and remaining life technique. APS has developed its proposed depreciation rates for production facilities by unit and by type of plant in service at each unit. This appears consistent with the development of depreciation rates for APS that was accepted by the Commission in APS' prior rate cases, Docket Nos. E-01345A-03-0437 and E-01345A-08-0172.

[42] See, e.g., Decision No. 71448, Settlement Agreement, Section XI at page 10.

APS' proposed depreciation rates also reflect a redistribution of recorded reserves. It is generally considered appropriate and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon more current estimates of retirement dispersion and net salvage rates. Statement C of Exhibit REW-2 provides a comparison of recorded, computed and redistributed reserves at December 31, 2010. The recorded reserve of $4.210 billion was 38.2 percent of the depreciable plant investment. The corresponding computed reserve of $3.367 billion is 30.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $842.1 million is amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation proposed in the study.

APS' depreciation rates also include amortization accounting for various general plant accounts.

Q. What impact do the new depreciation rates proposed by APS have?

A. As summarized on page 13 of Dr. White's testimony, based on December 31, 2010 plant investment, the new depreciation rates proposed by APS for APS plant decrease depreciation expense by $41.301 million (from $305.368 million at present rates to $264.067 million at APS' proposed rates). Of the 170 plant accounts studied in the 2011 study, APS proposes depreciation rate reductions for 97 accounts and increases for 73 accounts.[43]

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[43] *See*, e.g., Attachment REW-2, 2011 Depreciation Rate Study, page 4.

On a composite basis[44], the Company's proposed new rates for APS plant produce a decrease of 0.37 percentage points, from the current composite rate of 2.77 percent to a composite at new rates of 2.40 percent.

Q. Are there particular aspects of APS' proposed depreciation rates which warrant further discussion?

A. Yes. In particular, APS' proposed new depreciation rates for meters, APS' depreciation changes related to the Four Corners plant, and depreciation changes related to the operating license extension obtained by APS for the Palo Verde Nuclear Generating Station would appear to warrant further discussion. I address each of these areas below.

APS Proposed Depreciation Rates for Meters

Q. Please discuss APS' depreciation proposal for meters.

A. As discussed in APS' last rate case, Docket No. E-01345A-08-0172, APS has committed to a program of replacing electronic and electromechanical meters (Accounts 370.01 and 370.02, respectively) with Advanced Metering Infrastructure (Meters-AMI, Account 370.03).

APS' 2011 depreciation study shows no investment remaining in Account 370.02, electromechanical meters.

APS proposes to reduce the depreciable life for electronic meters (Account 370.01) and for Meters-AMI (account 370.3) from the current life of 26 years to a new life of only 15 years. Primarily related to this proposed service life shortening, APS proposes to increase the depreciation rate for electronic meters (Account 370.01) and for Meters-AMI (account

[44] Id, at page 3. APS does not apply its depreciations on a composite basis; this information is for comparative purposes only.

370.3) from the current rates of 3.68 percent and 3.82 percent, respectively, to new APS-proposed rates of 6.21 percent and 6.53 percent, respectively.[45]

Q. Does Staff agree with APS' proposal to shorten the average service life for meters from the current life of 26 years to a new life of only 15 years?

A. No. Staff disagrees with that proposed change and recommends that the current average service life of 26 years for meters continue to be used. Section C-11 of my testimony, on pages 61-67, presents the reasons for this recommendation, and the related Staff adjustment to depreciation expense.

Four Corners Related Depreciation Changes

Q. What ownership changes for the Four Corners coal-fired power plant are currently pending?

A. Four Corners is a five-unit coal-fired power plant located in the northwestern corner of New Mexico. APS owns 100 percent of Four Corners Units 1-3 and 15 percent of Four Corners Units 4 and 5. In November 2010, APS and Southern California Edison entered into an asset purchase agreement providing for the purchase by APS of SCE's 48 percent interest in Units 4 and 5. APS has indicated that completion of the purchase by APS is expected to occur in the second half of 2012, and is conditioned upon receipt of regulatory approval by the ACC, the California Public Utilities Commission and the FERC, and the execution of a new coal supply contract, and other typical closing conditions.

APS has announced that, if APS' purchase of the SCE interests in Four Corners Units 4 and 5 is consummated, APS will close Units 1, 2 and 3 at the plant. These events will

[45] See, e.g., Attachment REW-2, page 18. The new APS proposed depreciation rate for electronic meters is based on a 6.24 percent rate for investment cost recovery and a negative 0.03 percent net salvage rate.

change the plant's overall generating capacity from 2,100 MW to 1,540 MW and APS' entitlement from the plant from 791 MW to 970 MW.

Q. How did the APS depreciation study reflect the proposed purchase of Four Corners Units 4 and 5, and the subsequent shutdown of Units 1 through 3?

A. The APS depreciation study only uses the Four Corners plant balances for the current APS ownership share. APS reflected the proposed closure of Four Corners Units 1-3 by setting the rebalanced depreciation reserves for Four Corners Units 1-3 equal to computed reserves derived from an estimated 2012 year of shutdown. Estimated dismantlement costs for Units 1-3 were added to the estimated dismantlement costs for Units 4 and 5, and reserves were rebalanced over all steam production units. This treatment marginally increased the unrecovered investment in plants other than Four Corners and allocated the unrecovered investment in Four Corners Units 1-3 over the longer estimated average remaining lives of other steam units.[46] Based on the proposed retirement of Four Corners Units 1-3 by the end of 2012, APS decreased the annual depreciation accrual for those units from $24.630 million at current depreciation rates to zero at APS' proposed rates.[47]

As shown on page 75 of the depreciation study, the anticipated year of retirement for Four Corners Units 1-3 was adjusted from 2016 to 2012. With respect to Four Corners Units 4 and 5 and Four Corners common plant, the APS depreciation study, at page 75, reflected a revision of the anticipated retirement year from 2016 to 2038.

As shown on page 28 of the depreciation study, APS has reduced the annualized depreciation accrued for Four Corners, Units 1-3, from $24.630 million at current rates to zero at proposed depreciation rates.

[46] *See*, e.g., Direct Testimony of APS witness Ronald White at page 10.
[47] *See*, e.g., Attachment REW-2, page 28.

Q. Does Staff generally agree with APS' proposed depreciation changes relating to Four Corners?

A. Yes. While there continues to be some uncertainty as to the ownership changes related to Four Corners which will likely affect the remaining service lives, APS' proposed depreciation changes relating to Four Corners appear to be generally reasonable based on currently available information. The depreciation changes APS has proposed related to Four Corners also appear to be consistent with APS' announced closure of Four Corners Units 1-3 and a life extension of Four Corners Units 4 and 5, if APS' proposed purchase of SCE's interests in Units 4 and 5 is consummated. However, if that purchase is not consummated or if other information becomes available indicating that a different operating life scenario is more likely, the Four Corners depreciation impacts may need to be revised.

Palo Verde Nuclear Generating Station Operating License Extension

Q. How did the APS depreciation study reflect the Palo Verde Nuclear Generating Station operating license extension?

A. As shown on pages 76-77 of the depreciation study, the anticipated year of retirement for each of the Palo Verde generation units, and for the Palo Verde water reclamation system and common plant was also extended by 20 years beyond the retirement dates that had been used prior to the operating license extension.

Q. Does Staff concur with the Palo Verde related depreciation changes proposed by APS?

A. Yes.

Staff Recommendation on Depreciation Rates

Q. How should the depreciation rates proposed by APS be adopted for use in this case?

A. With the exception of Account 370.01, Electronic Meters, and Account 370.03, AMI Meters, the depreciation rates proposed by APS presented in Dr. White's Attachment REW-2 should be adopted for use in this case.[48] The depreciation rates proposed by APS were developed in a manner that is consistent with the Commission's rules for depreciation rates. My review of the details provided in Dr. White's Attachment REW-2 and other information indicates that those new rates proposed by APS are consistent with a reasonable approach to updating the depreciation rates that the Commission approved in Decision Nos. 67744, 69663 and 71448. I discuss the reasons for rejecting APS' proposed depreciation rate changes for electronic and AMI meter plant in Accounts 370.01 and 370.03, respectively, in my testimony on pages 61-67, in conjunction with Staff adjustment C-11.

SPECIAL RATEMAKING TREATMENT FOR IMPACT OF APS' ACQUISITION OF SCE'S OWNERSHIP INTEREST IN FOUR CORNERS UNITS 4 AND 5

Q. How could APS' ownership in Four Corners generating units be affected by its potential acquisition from Southern California Edison of SCE's interests in Four Corners, Units 4 and 5?

A. As described above in my discussion of depreciation rates, APS currently owns 15 percent of Four Corners Units 4 and 5, and has announced an agreement with SCE to acquire SCE's 48 percent interest in those units. APS owns 100 percent of Four Corners Units 1, 2, and 3, which are older less efficient generating units, and has announced its intention to retire those older units if its acquisition of SCE's ownership interests in Four Corners Units 4 and 5 is consummated.

[48] An additional adjustment may also be needed for the prospective annual depreciation of the Four Corners generating plant if APS' proposed acquisition of SCE's interest in Four Corners Units 4 and 5 is not consummated.

Q. What ratemaking treatment has APS requested related to its potential acquisition of SCE's interests in Four Corners, Units 4 and 5?

A. APS has asked for approval of new depreciation rates which reflect an extended service life for Four Corners, Units 4 and 5, that would apply in the event that APS acquires these units. APS has also reflected the cessation of annual depreciation accruals for Four Corners Units 1-3 based on its proposal to retire those units by the end of 2012.

In the current base rate case, APS has included in rate base only the cost for the share of Four Corners that APS already owns. APS has not proposed to include its cost of purchasing the SCE 48 percent interest in Four Corners Units 4 and 5 in its rate base in the current base rate case.

However, APS proposes in its rate case that the costs associated with acquiring SCE's ownership interest in those units would be recovered through APS' proposed Environmental and Reliability Account ("ERA") mechanism. Pursuant to that mechanism, APS' rates would be adjusted in the year after the units were acquired.

Q. Is Staff recommending approval of APS' proposed ERA?

A. No, as described in the Direct Testimony of Staff witness McGarry, Staff recommends that the Company's proposed ERA should be rejected.

Q. Is APS' acquisition of SCE's interest in Four Corners Units 4 and 5 a "known and measurable" change for purposes of determining APS' rate base in this proceeding?

A. No. APS' application (Docket No. E-01345A-10-0474) to acquire SCE's interest in Units 4 and 5 and its related proposal to shut down Units 1, 2, and 3 has not yet been approved. APS projects that the proposed transaction may be consummated in the second half of

2012, pending receipt of regulatory approvals. Because of the uncertainty associated with APS' acquisition and the resultant fate of the Four Corners plant, it would be inappropriate to include costs for APS' acquisition of SCE's ownership interests in Units 4 and 5 in (or to correspondingly remove Units 1, 2, and 3 from) APS' rate base at this time.

Q. **How does this affect the timing of APS' ability to recover the costs of these units if APS proceeds with the acquisition?**

A. Ordinarily, APS would have to wait until its next rate case, at which time the Company would ask to have its cost of acquiring SCE's ownership interests in Four Corners Units 4 and 5 included in rate base and presumably to have Units 1, 2, and 3 removed from rate base. Assuming that the transaction was found to be prudent, APS would begin recovering the costs of the acquired units at the close of its next rate case, *i.e.*, once its new rates from that case become final. This is the normal procedure for ratemaking, and it would not be an inappropriate result in this situation.

I would note that, in Docket No. E-01345A-10-0474, APS has requested a deferral order for certain costs related to Four Corners, Units 4 and 5. In that application, APS has also asked to defer certain costs related to the shutdown of Four Corners Units 1, 2 and 3. If that request were approved, APS would be able to seek recovery of those deferred costs in its next rate case as well.

Q. **Is Staff recommending that the Commission consider another alternative for the ratemaking treatment for Four Corners, Units 4 and 5?**

A. Yes. For a number of reasons, Staff is recommending that the Commission consider holding this case open solely for the purpose of addressing the ratemaking treatment of

Four Corners. This would allow APS to seek to include the costs of these units in rates once it has acquired them, instead of waiting until its next rate case.

Q. Why is Staff making this recommendation?

A. Staff believes that the posture of this case and the circumstances presented by it warrant consideration of this treatment. I would note that this recommendation is a departure from ordinary ratemaking procedures, and Staff would not make this recommendation absent compelling circumstances.

Q. What are the compelling circumstances?

A. In the past, APS has had less than ideal credit ratings. In the last rate case, the parties entered a Settlement Agreement, which, among other things, sought to position APS to be able to improve its financial metrics. I would note that APS' financial metrics appear to have improved, as discussed in the testimony of Staff witness Parcell.

Q. Are there benefits to ratepayers of APS' maintaining an investment-grade credit rating?

A. Yes. An investment-grade credit rating enables the Company to obtain capital at lower interest rates. These capital-cost savings are passed on to ratepayers in the form of lower rates.

Q. If APS' credit metrics have improved, as you noted above, why is Staff recommending that the Commission consider special ratemaking treatment in the current APS rate case for the Four Corner's acquisition?

A. In this case, Staff has calculated a small revenue sufficiency, which would result in a base rate decrease for APS. On the other hand, if APS were to acquire SCE's interest in Four

Corners, Units 4 and 5, the Company could be subject to increased costs, which would not be recoverable under normal circumstances until APS' next rate case. Providing for a special ratemaking treatment may help APS not only in maintaining its investment grade bond ratings but also to acquire a resource that could produce substantial net benefits for APS' ratepayers versus other alternatives. Overall net savings are anticipated by APS to result from that acquisition.[49]

Some of the cost decreases resulting from that acquisition, such as the lower fuel costs that APS projects[50], would commence providing benefits to ratepayers through the operation of the PSA mechanism. However, as noted above, under ordinary ratemaking procedures, the Company would not be able to recover its cost of plant investment and related costs such as depreciation and property taxes until the conclusion of its next rate case. A special ratemaking treatment would provide for the non-fuel cost recovery issues related to Four Corners to be addressed on a more timely basis.

Additionally, the accounting deferrals being addressed in Docket No. E-01345A-10-0474 would have less time to grow, and thus would likely become less of a future burden upon ratepayers if such deferrals are addressed promptly after APS' acquisition of the SCE interests in Four Corners Units 4 and 5 is consummated, rather than allowing such deferrals to grow until they can be considered in the context of APS' next base rate case.

[49] Testimony in Docket No. E-01345A-10-0474 describes how the proposed transaction is a genuine, unanticipated opportunity for APS to acquire a power resource that APS anticipates will provide unique value to APS' customers. APS has stated that the proposed transaction results in a system-wide revenue requirement that has net present value that is $488 million less than the next least expensive alternative of replacing 791 MW with combined-cycle natural gas generation and $1.08 billion less than the alternative of investing in environmental upgrades for Four Corners Units 1-3. See, e.g., APS witness Dinkel's Direct Testimony in that docket, at page 7.

[50] See, e.g., Attachment RCS-2, Schedule C-9, column F, line 10, which shows the incremental fuel cost savings that APS estimates with Four Corners 4&5 acquisition of $31.4 million. Reduced fuel costs reflect in part the higher efficiency of Four Corners Units 4&5 over Units 1 through 3.

Under these circumstances, Staff believes that a means of reducing the regulatory lag associated with cost recovery for the acquisition of SCE's interest in the Four Corners Units 4 and 5 (if the acquisition is determined to be prudent) is an option worthy of consideration in the current APS case due to the unique circumstances involved.

Q. Would it be unreasonable for the Commission to reject the special ratemaking procedure that you have described above?

A. This issue is essentially a policy matter for the Commission's consideration. It would not be *unreasonable* for the Commission to reject this proposal and instead go forward with routine ratemaking procedures. Staff offers this opinion to provide the Commission with a means to balance the effects of a modest rate decrease with the effects of a proposed acquisition that, if executed, will likely increase APS' plant investment and related costs.[51]

Q. Should the case be held open indefinitely?

A. No. This rate case is anticipated to be completed sometime in the summer of 2012. The Four Corners acquisition is anticipated to occur no later than October, 2012, and is conditioned upon APS receiving required regulatory approvals.[52] If APS wishes to take advantage of this proposal, Staff recommends that it file its ratemaking request related to its acquisition of Four Corners no later than December 30, 2012. Staff recommends that the rate case be held open solely on the Four Corners acquisition issue.

[51] As described in Docket No. E-01345A-10-0474, all proposed alternatives related to Four Corners would cause customer bills to rise; however, APS has represented that the proposed transaction would cause customer bills to increase by the least amount. See, e.g., Direct Testimony of Staff witness Laura Furrey, at pages 21-22.
[52] See, e.g., APS Schedule E-9 (SEC Form 10-K- for period ending 12/31/2010), pages 11-12 of 374.

Q. What would APS' filing, upon the Company's consummation of the acquisition of SCE's interest in Four Corners, Units 4 and 5, and the related proceeding entail?

A. The proceeding would include consideration of the rate base and expense effects associated with the acquisition of Units 4 and 5 as well as rate base and expense effects associated with the retirement of Units 1, 2, and 3. A very important matter to note is that this filing would include a prudence review of the transaction and of any deferred costs for which the Company would seek recovery. Any rate adjustment would be contingent upon the Commission finding that the acquisition and related costs were prudent.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments
Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)

R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
08-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

****APS Confidential Information Has Been Redacted****

Schedule	Description	Pages	Confidential	Exhibit Page No.
	Revenue Requirement Summary Schedules			
A	Calculation of Revenue Deficiency (Sufficiency)	2	No	2-3
A-1	Gross Revenue Conversion Factor	1	No	4
B	Adjusted Rate Base	1	No	5
B.1	Summary of Adjustments to Rate Base	2	No	6-7
C	Adjusted Net Operating Income	1	No	8
C.1	Summary of Net Operating Income Adjustments	3	No	9-11
D	Capital Structure and Cost Rates	1	No	12
	Rate Base Adjustments			
B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	1	No	13
B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	1	No	14
B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	1	No	15
B-4	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	1	No	16
B-5	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	1	No	17
B-6	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	2	No	18-19
B-7	Cash Working Capital	3	No	20-22
	Net Operating Income Adjustments			
C-1	Forensic Investigation of Grant-Funded Projects	1	No	23
C-2	General Advertising Expense	1	No	24
C-3	Property Tax Expense	1	No	25
C-4	Solar Post Test Year Plant Depreciation and Property Tax Expense	1	No	26
C-5	Fossil Post Test Year Plant Depreciation and Property Tax Expense	1	No	27
C-6	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	1	No	28
C-7	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense	1	No	29
C-8	Interest Synchronization	1	No	30
C-9	Base Fuel and Purchased Power	1	No	31
C-10	Payroll Expense Adjustment - New Union Contract	1	No	32
C-11	Depreciation Expense - New Depreciation Rates	1	No	33
C-12	Prospective Amortization of 2010 Severance Costs	1	No	34
C-13	Directors and Officers' Liability Insurance Expense	1	No	35
C-14	Incentive Compensation	1	Yes	36
C-15	Normalized Fossil Non-Plant Maintenance Expense	2	No	37-38
C-16	Edison Electric Institute Dues	2	No	39-40
	Total Pages, Including Content Listing	40		

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Schedule A
Page 1 of 2

Arizona Public Service Company
Computation of Increase in Gross Revenue Requirement

Test Year Ended December 31, 2010
(Thousands of Dollars)

Staff ROE: 9.90%

Line No.	Description	Reference	APS Proposed Original Cost (A)	APS Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value Alt 1 (D1)	Staff Proposed Fair Value Alt 2 (D2)	Difference Fair Value (E)=D2-B
1	Adjusted Rate Base	Sch. B	$ 5,720,277	$ 8,224,405	$ 5,662,998	$ 8,167,126	$8,167,126	$ (57,279)
2	Rate of Return	Sch. D	8.87%	6.17%	8.28%	5.74%	6.05%	
3	Operating Income Required		$ 507,389	$ 507,389	$ 468,818	$ 468,818	$ 493,859	$ (13,530)
4	Net Operating Income Available	Sch. C	$ 474,356	$ 474,356	$ 498,355	$ 498,355	$ 498,355	$ 23,999
5	Operating Income Excess/Deficiency		$ 33,033	$ 33,033	$ (29,537)	$ (29,538)	$ (4,496)	$ (37,529)
6	Gross Revenue Conversion Factor	Sch. A-1	1.6532	1.6532	1.6566	1.6566	1.6566	
7	Revenue Deficiency (Sufficiency)		$ 54,610	$ 54,610	$ (48,932)	$ (48,932)	$ (7,449)	$ (62,059)
8	Fair Value Increment			$ 40,883				$ (40,883)
9	Total Revenue Deficiency (Sufficiency)			$ 95,493		$ (48,932)	$ (7,449)	$ (102,942)
	Percentage Increase Over Current Rates							
10	Revenue from Sales to Ultimate Retail Customers	Sch C, L.1		$ 2,868,858		$ 2,868,858	$2,868,858	
11	Percentage Increase - Total	L9/L15		3.33%		-1.71%	-0.26%	

Notes and Source
Cols. A & B taken from APS filing, Schedule A-1

Arizona Public Service Company
Revenue Requirement Reconciliation
Test Year Ended December 31, 2010

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Schedule A
Page 2 of 2

(Thousands of Dollars)

Line No.	Description	Schedule	Staff Adjustments (A)	Conversion Factor (B)	Equivalent Revenue Requirement Amount (C)
1	**Rate of return difference**	D		-0.59%	
2	Staff GRCF	A-1		1.6566	
3	**Rate Base**			-0.982843%	
4	Original Cost Rate Base per APS' Filing	B	$ 5,720,277		$ (56,221)
5	Staff ROR	D		8.28%	
6	Staff ROR x GRCF			13.71%	
	Effect of Staff adjustments to Rate Base				
7	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant	B-1	$ (35,406)	13.71%	$ (4,856)
8	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant	B-2	$ (23,458)	13.71%	$ (3,217)
9	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant	B-3	$ (17,536)	13.71%	$ (2,405)
10	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant	B-4	$ (53,196)	13.71%	$ (7,295)
11	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012	B-5	$ 60,124	13.71%	$ 8,246
12	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012	B-6	$ 1,726	13.71%	$ 237
13	Cash Working Capital	B-7	$ 10,467	13.71%	$ 1,436
12	Total Staff Original Cost Rate Base Adjustments		$ (57,279)		
13	**Staff Adjusted Original Cost Rate Base**		$ 5,662,998		
	Net Operating Income				
14	Net Operating Income per APS' Filing		$ 474,356		
15	**Effect of Staff Adjustments on NOI**			GRCF	
16	Forensic Investigation of Grant-Funded Projects	C-1	$ 1,244	1.65660	$ (2,061)
17	General Advertising Expense	C-2	$ 346	1.65660	$ (573)
18	Property Tax Expense	C-3	$ 353	1.65660	$ (585)
19	Solar Post Test Year Plant Depreciation and Property Tax Expense	C-4	$ 787	1.65660	$ (1,304)
20	Fossil Post Test Year Plant Depreciation and Property Tax Expense	C-5	$ 473	1.65660	$ (784)
21	Nuclear Post Test Year Plant Depreciation and Property Tax Expense	C-6	$ 220	1.65660	$ (364)
22	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense	C-7	$ 1,611	1.65660	$ (2,669)
23	Interest Synchronization	C-8	$ (638)	1.65660	$ 1,057
24	Base Fuel and Purchased Power	C-9	$ 5,792	1.65660	$ (9,595)
25	Payroll Expense Adjustment - New Union Contract	C-10	$ (3,021)	1.65660	$ 5,005
26	Depreciation Expense - New Depreciation Rates	C-11	$ 2,864	1.65660	$ (4,744)
27	Prospective Amortization of 2010 Severance Costs	C-12	$ 1,892	1.65660	$ (3,134)
28	Directors and Officers' Liability Insurance Expense	C-13	$ 333	1.65660	$ (551)
29	Incentive Compensation	C-14	$ 11,451	1.65660	$ (18,970)
30	Normalized Fossil Non-Plant Maintenance Expense	C-15	$ 161	1.65660	$ (267)
31	Edison Electric Institute Dues	C-16	$ 131	1.65660	$ (217)
32	Total Staff Adjustments to Operating Income		$ 23,999		
33	**Staff Adjusted Net Operating Income**		$ 498,355		
	Gross Revenue Conversion Factor Difference:				
34	Per Staff			1.65660	
35	Per Company			1.65320	
36	Difference			0.00340	
37	Company adjusted NOI deficiency			$ 33,033	
38	GRCF difference				$ 112
39	STAFF REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED ABOVE				$ (103,719)
40	Company requested Base Rate Revenue Increase on OCRB	Schedule A, page 1, column A, line 9			$ 54,610
41	Reconciled Revenue Requirement				$ (49,109)
42	Revenue Requirement Calculated on OCRB	Schedule A, page 1, column C, line 9			$ (48,932)
43	Difference				$ (177)
44	Difference Attributed to APS Rate of Return Rounding	Line 50, below			$ (180)
45	Unidentified Difference				$ 3

Notes and Source
Pre-tax return computed using Gross Revenue Conversion Factor
Difference related to rounding in calculation of Company requested Base Rate Revenue Increase on OCRB

	Component	Per APS (ROR Rounded)	Per APS Without Rounding	Difference
46	Rate Base	$ 5,720,277	$ 5,720,277	
47	Rate of Return	8.87%	8.87190%	
48	Required Return	$ 507,389	$ 507,497	$ (109)
49	GRCF			1.6532
50	Revenue Requirement Impact of APS Rate of Return Rounding			$ (180)

Arizona Public Service Company
Computation of Gross Revenue Conversion Factor

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Schedule A-1
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Company (A)	Staff Proposed (B)
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectible Revenue		0.21%
3	Taxable Income as a Percent	100.00%	99.79%
4	Less: Federal Income Taxes	32.57%	32.50%
5	Taxable Income as a Percent	67.43%	67.29%
6	Less: State Income Taxes	6.94%	6.93%
7	Change in Net Operating Income	60.49%	60.36%
8	Gross Revenue Conversion Factor	1.6532	1.6566
9	Combined state and federal income tax rate	39.51%	39.51%

Notes and Source
Col.A: APS Filing, Schedule C-3
Col.B: Staff included the uncollectible rate of 0.21% based on APS' response to data request Staff 25.11.

Components of Revenue Requirement Increase ($000's)

		Percent (C)	Fair Value Alt 1 (D)	Fair Value Alt 2 (E)
10	Net Income	60.36%	(29,537)	(4,496)
11	Federal Income Taxes	32.50%	(15,904)	(2,421)
12	State Income Taxes	6.93%	(3,389)	(516)
13	Uncollectibles	0.21%	(103)	(16)
14	Total Revenue Increase	100.00%	(48,932)	(7,449)
15	Total Revenue Increase per Schedule A		$ (48,932)	$ (7,449)
14	Difference		-	(0)

Arizona Public Service Company
Original Cost and RCND Adjusted Rate Base
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Original Cost by APS (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by APS (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 12,467,614	$ (129,596)	$ 12,338,018	$ 23,201,276	$ (129,596)	$ 23,071,680
2	Less: Accumulated Depreciation	$ (5,015,939)	$ 60,124	$ (4,955,815)	$ (9,014,923)	$ 60,124	$ (8,954,799)
3	Net Utility Plant in Service	$ 7,451,675	$ (69,472)	$ 7,382,203	$ 14,186,353	$ (69,472)	$ 14,116,881
	Deductions:						
4	Deferred Income Taxes	$ (1,615,133)	$ 1,726	$ (1,613,407)	$ (3,341,556)	$ 1,726	$ (3,339,830)
5	Investment Tax Credits	$ (876)	$ -	$ (876)	$ (876)	$ -	$ (876)
6	Customer Advances for Construction	$ (121,645)	$ -	$ (121,645)	$ (121,645)	$ -	$ (121,645)
7	Customer Deposits	$ (68,084)	$ -	$ (68,084)	$ (68,084)	$ -	$ (68,084)
8	Pension and Other Postretirement Liabilities	$ (661,518)	$ -	$ (661,518)	$ (661,518)	$ -	$ (661,518)
9	Liability For Asset Retirement	$ (320,592)	$ -	$ (320,592)	$ (320,592)	$ -	$ (320,592)
10	Other Deferred Credits	$ (64,107)	$ -	$ (64,107)	$ (64,107)	$ -	$ (64,107)
11	Coal mine reclamation	$ (114,396)		$ (114,396)	$ (114,396)		$ (114,396)
12	Unamortized Gain-Sale of Utility Plant	$ (53,961)	$ -	$ (53,961)	$ (53,961)	$ -	$ (53,961)
13	Regulatory Liabilities	$ (253,750)	$ -	$ (253,750)	$ (253,750)	$ -	$ (253,750)
14	Total Deductions	$ (3,274,062)	$ 1,726	$ (3,272,336)	$ (5,000,485)	$ 1,726	$ (4,998,759)
	Additions:						
14	Construction Work in Progress	$ -	$ -	$ -	$ -	$ -	$ -
15	Regulatory Assets	$ 746,508	$ -	$ 746,508	$ 746,508	$ -	$ 746,508
16	Deferred debit income tax receivable	$ 63,271		$ 63,271	$ 63,271		$ 63,271
17	Other Deferred Debits	$ 72,203	$ -	$ 72,203	$ 72,203	$ -	$ 72,203
18	Decommissioning Trust Accounts	$ 458,476	$ -	$ 458,476	$ 458,476	$ -	$ 458,476
19	Allowance For Working Capital	$ 202,206	$ 10,467	$ 212,673	$ 202,206	$ 10,467	$ 212,673
20	Total Additions	$ 1,542,664	$ 10,467	$ 1,553,131	$ 1,542,664	$ 10,467	$ 1,553,131
20	Total Rate Base	$ 5,720,277	$ (57,279)	$ 5,662,998	$ 10,728,532	$ (57,279)	$ 10,671,253

Notes and Source
Cols. A and D: APS filing, Schedule B-1

Fair Value Calculation (Per Company)

Original Cost	$ 5,720,277	
RCND	$ 10,728,532	
Total	$ 16,448,809	
Average (Fair Value)	$ 8,224,405	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 5,662,998	
RCND	$ 10,671,253	
Total	$ 16,334,251	
Average (Fair Value)	$ 8,167,126	See Sch. A

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Schedule B.1
Page 1 of 1

Arizona Public Service Company
Summary of Rate Base Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Staff Adjustments	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible Plant B-4	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012 B-5	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012 B-6	Cash Working Capital B-7
1	Gross Utility Plant in Service	$ (129,596)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)			$ -
2	Less: Accumulated Depreciation	$ 60,124					$ 60,124		
3	Net Utility Plant in Service	$ (69,472)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ -	$ -
	Deductions:								
4	Deferred Income Taxes	$ 1,726						$ 1,726	
5	Investment Tax Credits	$ -							
6	Customer Advances for Construction	$ -							
7	Customer Deposits	$ -							
8	Pension and Other Postretirement Liabilities	$ -							
9	Liability For Asset Retirement	$ -							
10	Other Deferred Credits	$ -							
11	Unamortized Gain-Sale of Utility Plant	$ -							
12	Regulatory Liabilities	$ -							
13	**Total Deductions**	$ 1,726	$ -	$ -	$ -	$ -	$ -	$ 1,726	$ -
	Additions:								
14	Construction Work in Progress	$ -							
15	Regulatory Assets	$ -							
16	Other Deferred Debits	$ -							
17	Decommissioning Trust Accounts	$ -							
18	Allowance For Working Capital	$ 10,467							$ 10,467
19	**Total Additions**	$ 10,467	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,467
		$ -							
20	Total Rate Base	$ (57,279)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ 1,726	$ 10,467

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Schedule B.1 (RCND)
Page 1 of 1

Arizona Public Service Company
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated - ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Line No.	Description	Staff Adjustments	Post-Test Year Plant Additions - Through 3/31/2012 - Solar Plant B-1	Post-Test Year Plant Additions - Through 3/31/2012 - Fossil Plant B-2	Post-Test Year Plant Additions - Through 3/31/2012 - Nuclear Plant B-3	Post-Test Year Plant Additions - Through 3/31/2012 - Distribution and General and Intangible B-4	Accumulated Depreciation - Post Test Year Adjustment Through 3/31/2012 B-5	Accumulated Deferred Income Taxes - Post Test Year Adjustment Through 3/31/2012 B-6	Cash Working Capital B-7
1	Gross Utility Plant in Service	$ (129,596)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ -		
2	Less: Accumulated Depreciation	$ 60,124	$ -				$ 60,124		
3	Net Utility Plant in Service	$ (69,472)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124		$ -
	Deductions:								
4	Deferred Income Taxes	$ 1,726		$ -				$ 1,726	
5	Investment Tax Credits	$ -							
6	Customer Advances for Construction	$ -							
7	Customer Deposits	$ -							
8	Pension and Other Postretirement Liabilities	$ -							
9	Liability For Asset Retirement	$ -							
10	Other Deferred Credits	$ -							
11	Unamortized Gain-Sale of Utility Plant	$ -							
12	Regulatory Liabilities	$ -							
13	**Total Deductions**	$ 1,726	$ -	$ -	$ -	$ -	$ -	$ 1,726	$ -
	Additions:								
14	Construction Work in Progress	$ -							
15	Regulatory Assets	$ -							
16	Other Deferred Debits	$ -							
17	Decommissioning Trust Accounts	$ -							
18	Allowance For Working Capital	$ 10,467							$ 10,467
19	**Total Additions**	$ 10,467	$ -	$ -	$ -	$ -	$ -		$ 10,467
20	Total Rate Base	$ (57,279)	$ (35,406)	$ (23,458)	$ (17,536)	$ (53,196)	$ 60,124	$ 1,726	$ 10,467

Arizona Public Service Company
Adjusted Net Operating Income
ACC Jurisdictional
Test Year Ended December 31, 2010
(Thousand of Dollars)

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Schedule C
Page 1 of 1

Line No.	Description	As Adjusted by APS (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Revenues From Base Rates	$ 2,868,858	$ -	$ 2,868,858
2	Revenues From Surcharges	$ -	$ -	$ -
3	Other Electric Revenues	$ 121,013	$ -	$ 121,013
4	Total Operating Revenues	$ 2,989,871	$ -	$ 2,989,871
	Operating Expenses			
5	Electric Fuel and Purchased Power	$ 1,015,598	$ (9,575)	$ 1,006,023
6	O&M Excluding Fuel Expenses	$ 808,018	$ (20,725)	$ 787,293
7	Depreciation & Amortization	$ 352,026	$ (8,488)	$ 343,538
8	Income Taxes	$ 200,456	$ 16,731	$ 217,187
9	Other Taxes	$ 139,417	$ (1,943)	$ 137,474
10	Total Operating Expenses	$ 2,515,515	$ (23,999)	$ 2,491,516
11	Net Operating Income	$ 474,356	$ 23,999	$ 498,355

Notes and Source
Col. A: APS Schedule C-1, page 2 of 2
Col. B: Staff Schedule C.1

Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

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Schedule C.1
Page 1 of 3

Line No.	Description	Staff Adjustments	Forensic Investigation of Grant-Funded Projects C-1	General Advertising Expense C-2	Property Tax Expense C-3	Solar Post Test Year Plant Depreciation and Property Tax Expense C-4	Fossil Post Test Year Plant Depreciation and Property Tax Expense C-5	Nuclear Post Test Year Plant Depreciation and Property Tax Expense C-6
	Operating Revenues							
1	Revenues From Base Rates	$ -						
2	Revenues From Surcharges	$ -						
3	Other Electric Revenues	$ -						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses							
5	Electric Fuel and Purchased Power	$ (9,575)						
6	O&M Excluding Fuel Expenses	$ (20,725)	$ (2,057)	$ (572)		$ -	$ -	$ -
7	Depreciation & Amortization	$ (8,488)				$ (1,170)	$ (637)	$ (253)
8	Other Taxes	$ (1,943)			$ (584)	$ (131)	$ (146)	$ (110)
9	PRE-TAX OPERATING EXPENSES	$ (40,730)	$ (2,057)	$ (572)	$ (584)	$ (1,301)	$ (783)	$ (363)
10	PRE-TAX OPERATING INCOME	$ 40,730	$ 2,057	$ 572	$ 584	$ 1,301	$ 783	$ 363
11	Income Taxes	$ 16,731	$ 813	$ 226	$ 231	$ 514	$ 310	$ 143
12	TOTAL OPERATING EXPENSES	$ (23,999)	$ (1,244)	$ (346)	$ (353)	$ (787)	$ (473)	$ (220)
13	OPERATING INCOME	$ 23,999	$ 1,244	$ 346	$ 353	$ 787	$ 473	$ 220

Notes and Source
Combined Effective Tax Rate* 39.51%
* Per APS filing, Schedule C-3

Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

Docket No. E-01345A-11-0224
Schedule C.1
Page 2 of 3

Line No.	Description	Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense C-7	Interest Synchronization C-8	Base Fuel and Purchased Power C-9	Payroll Expense Adjustment - New Union Contract C-10	Depreciation Expense - New Depreciation Rates C-11	Prospective Amortization of 2010 Severance Costs C-12
	Operating Revenues						
1	Revenues From Base Rates						
2	Revenues From Surcharges						
3	Other Electric Revenues					$ -	
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Electric Fuel and Purchased Power			$ (9,575)			
6	O&M Excluding Fuel Expenses	$ -			$ 4,994		$ (3,128)
7	Depreciation & Amortization	$ (1,693)	$ -	$ -		$ (4,735)	
8	Other Taxes	$ (971)	$ -	$ -			
9	PRE-TAX OPERATING EXPENSES	$ (2,664)	$ -	$ (9,575)	$ 4,994	$ (4,735)	$ (3,128)
10	PRE-TAX OPERATING INCOME	$ 2,664	$ -	$ 9,575	$ (4,994)	$ 4,735	$ 3,128
11	Income Taxes	$ 1,053	$ 638	$ 3,783	$ (1,973)	$ 1,871	$ 1,236
12	TOTAL OPERATING EXPENSES	$ (1,611)	$ 638	$ (5,792)	$ 3,021	$ (2,864)	$ (1,892)
13	OPERATING INCOME	$ 1,611	$ (638)	$ 5,792	$ (3,021)	$ 2,864	$ 1,892

Notes and Source
Combined Effective Tax Rate* 39.51%
* Per APS filing, Schedule C-3

Attachment RCS-2
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Arizona Public Service Company
Summary of Net Operating Income Adjustments
ACC Jurisdiction
Test Year Ended December 31, 2010
(Thousand of Dollars)

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Schedule C.1

Line No.	Description	Directors and Officers' Liability Insurance Expense	Incentive Compensation	Normalized Fossil Non-Plant Maintenance Expense	Edison Electric Institute Dues
		C-13	C-14	C-15	C-16
	Operating Revenues				
1	Revenues From Base Rates				
2	Revenues From Surcharges				
3	Other Electric Revenues				
4	Total Operating Revenues	$ -	$ -	$ -	$ -
	Operating Expenses				
5	Electric Fuel and Purchased Power				
6	O&M Excluding Fuel Expenses	$ (550)	$ (18,930)	$ (266)	$ (216)
7	Depreciation & Amortization				
8	Other Taxes				
9	PRE-TAX OPERATING EXPENSES	$ (550)	$ (18,930)	$ (266)	$ (216)
10	PRE-TAX OPERATING INCOME	$ 550	$ 18,930	$ 266	$ 216
11	Income Taxes	$ 217	$ 7,479	$ 105	$ 85
12	TOTAL OPERATING EXPENSES	$ (333)	$ (11,451)	$ (161)	$ (131)
13	OPERATING INCOME	$ 333	$ 11,451	$ 161	$ 131

Notes and Source
Combined Effective Tax Rate* 39.51%
* Per APS filing, Schedule C-3

Arizona Public Service Company
Capital Structure & Cost Rates

Docket No. E-01345A-11-0224
Schedule D
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	APS - Proposed				
1	Short-Term Debt	$ -			0.00%
2	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
3	Common Stock Equity	$ 3,961,248	53.94%	11.00%	5.93%
4	Total Capital	$ 7,344,104	100.00%		8.87%
	ACC Staff - Proposed				
5	Short-Term Debt	$ -			0.00%
6	Long-Term Debt	$ 3,382,856	46.06%	6.38%	2.94%
7	Common Stock Equity	$ 3,961,248	53.94%	9.90%	5.34%
8	Total Capital	$ 7,344,104	100.00%		8.28%
9	Difference				-0.59%
10	Weighted Cost of Debt				2.94%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 1				
11	Short-Term Debt	$ -	0.00%	0.00%	0.00%
12	Long-Term Debt	$ 2,608,502	31.94%	6.38%	2.04%
13	Common Stock Equity	$ 3,054,497	37.40%	9.90%	3.70%
14	Capital financing OCRB	$ 5,662,998			
15	Appreciation above OCRB not recognized on utility's books	$ 2,504,128	30.66%	0% [a]	0.00%
16	Total capital supporting FVRB	$ 8,167,126	100.00%		5.74%
	ACC Staff - Proposed Fair Value Rate of Return - Alternative 2				
17	Short-Term Debt	$ -	0.00%	0.00%	0.00%
18	Long-Term Debt	$ 2,608,502	31.94%	6.38%	2.04%
19	Common Stock Equity	$ 3,054,497	37.40%	9.90%	3.70%
20	Capital financing OCRB	$ 5,662,998			
21	Appreciation above OCRB not recognized on utility's books	$ 2,504,128	30.66%	1.00% [b]	0.31%
22	Total capital supporting FVRB	$ 8,167,126	100.00%		6.05%

Notes and Source

Lines 1-4, APS filing D-1.

Line 15, Col.A:

23	Fair Value Rate Base	$ 8,167,126	Schedule A
24	Original Cost Rate Base	$ 5,662,998	Schedule A
25	Difference	$ 2,504,128	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

Arizona Public Service Company
Solar Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	277,411	267,979	240,759	232,573	(36,652)	(35,406)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Jeffrey B Guldner workpaper JBG_WP1
As updated by APS in response to STF 6.55, APS14743 and APS' response to STF 27.4(a):

Line No.	Description	Total Company (G)	ACC Jurisdictional (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 260,765	$ 251,899	$ (16,080)	45.42%
3	Additions from 4/1/2012 to 6/30/2012	$ 20,006	$ 19,326	$ (19,326)	54.58%
4	Additions from 1/1/2011 to 3/31/2012	$ 240,759	$ 232,573	$ (35,406)	100.00%

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Schedule B-2
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Arizona Public Service Company
Fossil Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line		Per Company Through 6/30/2012		Per Staff Through 3/31/2012		Staff Adjustment	
No.	Description	Total Company (A)	ACC (B)	Total Company (C)	ACC (D)	Total Company (E)	ACC (F)
1	Post Test Year Plant Additions	$ 156,269	$ 150,956	$ 131,985	$ 127,498	$ (24,284)	$ (23,458)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Mark A Schiavoni workpaper MAS_WP1
As updated by APS in response to STF 6.55, APS14744, and APS' response to STF 27.4(c):

Line	Description	Total Company (G)	ACC (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 154,606	$ 149,350	$ (1,606)	6.85%
3	Additions from 4/1/2012 to 6/30/2012	$ 22,621	$ 21,852	$ (21,852)	93.15%
4	Additions from 1/1/2011 to 3/31/2012	$ 131,985	$ 127,498	$ (23,458)	100.00%

Arizona Public Service Company
Nuclear Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	$ 120,103	$ 116,019	$ 101,950	$ 98,483	$ (18,153)	$ (17,536)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Randy K Edington workpaper RKE_WP1
As updated by APS in response to STF 6.55, APS14745 and APS' response to STF 27.4(b):

Line No.	Description	Total Company (G)	ACC (H)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 111,397	$ 107,609	$ (8,410)	47.96%
3	Additions from 4/1/2012 to 6/30/2012	$ 9,447	$ 9,126	$ (9,126)	52.04%
4	Additions from 1/1/2011 to 3/31/2012	$ 101,950	$ 98,483	$ (17,536)	100.00%

Arizona Public Service Company
Distribution, General and Intangible Post-Test Year Plant Additions

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per Company Through 6/30/2012 Total Company (A)	Per Company Through 6/30/2012 ACC (B)	Per Staff Through 3/31/2012 Total Company (C)	Per Staff Through 3/31/2012 ACC (D)	Staff Adjustment Total Company (E)	Staff Adjustment ACC (F)
1	Post Test Year Plant Additions	$ 432,984	$ 423,910	$ 378,649	$ 370,714	$ (54,335)	$ (53,196)

Notes and Source:
Cols A and B: Per APS Filing Schedule B-2
Cols C and D: APS witness Daniel T Froetscher workpaper DTF_WP1
As updated by APS in response to STF 6.55, APS14746 and APS' response to STF 27.4(d) and (e):

Line No.	Description	Total Company (G)	ACC (I)	Staff Jurisdictional Adjustment Components (I)	Staff Jurisdictional Adjustment Components Percent (J)
2	Additions from 1/1/2011 to 6/30/2012	$ 422,758	$ 413,898	$ (10,012)	18.82%
3	Additions from 4/1/2012 to 6/30/2012	$ 44,109	$ 43,184	$ (43,184)	81.18%
4	Additions from 1/1/2011 to 3/31/2012	$ 378,649	$ 370,714	$ (53,196)	100.00%

Arizona Public Services
Accumulated Depreciation
ACC Jurisdictional

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Schedule B-5
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Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Description	APS Original Filing, Change Through 6/30/2012 (A)	APS Update, Filing Change Through 6/30/2012 (B)	APS Update, Change Through 3/31/2012 (C)	Staff Adjustment (D) = C-A
1	Solar	$ (5,602)	$ (5,403)	$ (3,391)	$ 2,211
2	Fossil	$ (128,710)	$ (128,710)	$ (113,349)	$ 15,361
3	Nuclear	$ (92,675)	$ (92,675)	$ (94,045)	$ (1,370)
4	Distribution and General and Intangible	$ (263,596)	$ (263,596)	$ (219,674)	$ 43,922
5	Total	$ (490,583)	$ (490,384)	$ (430,459)	$ 60,124

Notes and Source
Amounts represent a decrease (increase) to the jurisdictional Accumulated Depreciation balance and (decrease) increase to rate base
Col A: APS Original Filing Schedule B-2, Pages 1 and 2 of 3
Col B: APS October 26, 2011 Update Schedule B-2 Pages 1 and 2 of 3
Col C: APS response to STF 27.6

Arizona Public Services
Accumulated Deferred Income Tax
ACC Jurisdictional

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	APS Original Filing, Change Through 6/30/2012 (A)	APS Update Filing, Change Through 6/30/2012 (B)	APS Update, Change Through 3/31/2012 (C)	Staff Adjustment (D) = C-A
1	Solar	$ (3,844)	$ (3,218)	$ (2,476)	$ 1,368
2	Fossil	$ (12,155)	$ (12,155)	$ (12,344)	$ (189)
3	Nuclear	$ (28,331)	$ (28,331)	$ (30,226)	$ (1,895)
4	Distribution and General and Intangible	$ (4,320)	$ (4,320)	$ (1,878)	$ 2,442
5	Total	$ (48,650)	$ (48,024)	$ (46,924)	$ 1,726

Notes and Source
Amounts represent a decrease (increase) to the jurisdictional ADIT balance and (decrease) increase to rate base
Col A: APS Original Filing Schedule B-2, Pages 1 and 2 of 3
Col B: APS October 26, 2011 Update Schedule B-2 Pages 1 and 2 of 3
Col C: APS response to STF 27.7
Note: the adjustment shown in column D is a temporary placeholder pending receipt of APS' actual March 31, 2012 ADIT balance similar to the information provided in APS' response to Staff 20.1, APS14858 and resolution of concerns about coordinating the rate base update to March 31, 2012 in a manner that will not implicate tax normalization concerns described in APS' responses to AECC 1.11, Staff 15.13, Staff 19.14 and other responses concerning the rate base update for ADIT balances.

Arizona Public Service Company
Accumulated Deferred Income Taxes - Accounts 190, 282, and 283

Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Account Description	Actuals Increase (Decrease) RATE BASE 7/31/11 (A)	Actuals Increase (Decrease) RATE BASE 8/31/11 (B)	Forecast Increase (Decrease) RATE BASE 9/30/11 (C)	Forecast Increase (Decrease) RATE BASE 10/31/11 (D)	Forecast Increase (Decrease) RATE BASE 11/30/11 (E)	Forecast Increase (Decrease) RATE BASE 12/31/11 (F)	Forecast Increase (Decrease) RATE BASE 1/31/12 (G)	Forecast Increase (Decrease) RATE BASE 2/29/12 (H)	Forecast Increase (Decrease) RATE BASE 3/31/12 (I)
	Total Company									
1	Total Deferred Taxes per General Ledger	$(1,819,235)	$(1,887,398)	$(1,888,657)	$(1,893,263)	$(1,891,763)	$ (1,893,834)	$(1,895,722)	$ (1,891,506)	$ (1,881,995)
	Exclude									
2	Reg Asset-Power Supply Adjustor Mark to Market	(24,929)	(24,929)	(18,418)	(17,861)	(18,042)	(17,792)	(17,719)	(17,882)	(18,323)
3	Reg Asset-Transmission Vegetation Management	(17,857)	(17,747)	(17,701)	(17,685)	(17,690)	(17,683)	(17,680)	(17,687)	(17,708)
4	Reg Asset-Unamortized Loss on Reaquired Debt	(8,346)	(8,187)	(8,120)	(8,097)	(8,105)	(8,094)	(8,089)	(8,100)	(8,130)
5	Option II Benefits (Includes Reg Asset and Def Comp)	4,272	3,879	3,712	3,653	3,672	3,646	3,640	3,653	3,689
6	Reg Asset-Demand Side Management	(4,351)	(2,806)	(2,151)	(1,922)	(1,997)	(1,894)	(1,876)	(1,916)	(2,025)
7	Reg Liab-Renewable Energy Standard	20,208	21,054	21,412	21,538	21,497	21,553	21,580	21,520	21,359
8	Reg Liab-Power Supply Adjustor	9,129	1,041	(2,391)	(3,588)	(3,198)	(3,736)	(3,703)	(3,776)	(3,974)
9	Renewable Energy Incentives	47,539	53,456	55,966	56,841	56,556	56,950	57,066	56,807	56,107
10	Mark to Market	74,908	64,472	82,448	81,877	82,063	81,806	81,730	81,900	82,362
11	OCI-Pension Taxes	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123
12	Superfund	1,758	1,711	1,691	1,684	1,686	1,683	1,682	1,685	1,694
13	Other	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039
14	Total Excluded	125,494	115,103	139,609	139,602	139,604	139,601	139,792	139,365	138,212
15	Total Accumulated Deferred Income Taxes	$(1,944,729)	$(2,002,501)	$(2,028,266)	$(2,032,865)	$(2,031,367)	$ (2,033,434)	$(2,035,514)	$ (2,030,872)	$ (2,020,207)
	ACC Jurisdictional									
16	Total Deferred Taxes per General Ledger	$(1,519,663)	$(1,576,602)	$(1,577,653)	$(1,581,501)	$(1,580,248)	$ (1,581,978)	$(1,583,556)	$ (1,580,034)	$ (1,572,089)
	Exclude									
17	Reg Asset-Power Supply Adjustor Mark to Market	(24,323)	(24,323)	(17,971)	(17,427)	(17,604)	(17,360)	(17,288)	(17,447)	(17,878)
18	Reg Asset-Transmission Vegetation Management	-	-	-	-	-	-	-	-	-
19	Reg Asset-Unamortized Loss on Reaquired Debt	(8,062)	(7,909)	(7,844)	(7,822)	(7,829)	(7,819)	(7,814)	(7,825)	(7,854)
20	Option II Benefits (Includes Reg Asset and Def Comp)	3,970	3,604	3,449	3,395	3,413	3,388	3,383	3,395	3,428
21	Reg Asset-Demand Side Management	(4,203)	(2,711)	(2,078)	(1,857)	(1,929)	(1,830)	(1,812)	(1,851)	(1,956)
22	Reg Liab-Renewable Energy Standard	19,521	20,338	20,684	20,805	20,766	20,820	20,846	20,788	20,633
23	Reg Liab-Power Supply Adjustor	8,908	1,015	(2,333)	(3,501)	(3,120)	(3,645)	(3,613)	(3,685)	(3,878)
24	Renewable Energy Incentives	46,383	52,157	54,606	55,460	55,182	55,566	55,679	55,427	54,744
25	Mark to Market	73,088	62,905	80,444	79,887	80,069	79,818	79,744	79,910	80,360
26	OCI-Pension Taxes	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559
27	Superfund	1,634	1,590	1,571	1,565	1,567	1,564	1,563	1,566	1,574
28	Other	966	966	966	966	966	966	966	966	966
29	Total Excluded	138,441	128,191	152,053	152,030	152,040	152,027	152,213	151,803	$ 150,698
30	Total Accumulated Deferred Income Taxes	$(1,658,104)	$(1,704,793)	$(1,729,706)	$(1,733,531)	$(1,732,288)	$ (1,734,005)	$(1,735,769)	$ (1,731,837)	$ (1,722,787)
31	APS original filing, adjusted ACC jurisdictional ADIT									$ (1,615,133)
32	Difference									$ (107,654)
33	APS October 26, 2011 update filing, jurisdicitonal ADIT									$ (1,614,507)
34	Difference									$ (108,280)

Notes and Source:
Lines 1 - 13: APS response to STF 15.7
Lines 16-30: APS response to STF 20.1 Bates No APS 14858
Line 31: APS' original filing, Schedule B-1, page 1 of 2, line 4, column F
Line 33: APS' October 26, 2011 update filing, Schedule B-1, page 1 of 2, line 4, column F

Arizona Public Service Company
Cash Working Capital

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Schedule B-7
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Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Staff Income Statement Adjustments (A)	CWC FACTOR (B)	Staff Adjustments to Cash Working Capital (C)
	Fuel For Electric Generation:			
1	Coal	$ 14,653	0.01082	$ 159
2	Natural Gas	$ (24,102)	0.01120	$ (270)
3	Gas Mtm And Futures		0.00000	
4	Handling	$ (72)	0.06251	$ (4)
5	Fuel Oil		-0.00290	
6	Nuclear:			
7	Amortization	$ 3,889	0.00000	$ -
8	Spent Fuel		-0.10669	
9	Total Nuclear Fuel	$ 3,889		$ -
10	Total Fuel	$ (5,632)		$ (116)
11	Purchased Power	$ (5,605)	0.00889	$ (50)
12	Power Mtm		0.00000	
13	Power Supply Adjuster		0.00000	
14	Transmission By Others	$ 1,663	-0.00170	$ (3)
15	Total Purchased Power & Transmission	$ (3,943)		$ (53)
16	Subtotal Fuel and Purchased Power	$ (9,575)		
	Other Operations & Maintenance:			
17	Payroll	$ 4,994	0.06251	
18	Incentive	$ (18,930)	-0.54541	$ 10,325
19	Stock Compensation	$ -	0.00000	
20	Severance (Excludes Pension)	$ (3,128)	-0.11090	$ 347
21	Pension and OPEB	$ -	-0.00025	
22	Employee Benefits	$ -	0.06708	
23	Payroll Taxes	$ -	-0.00520	
24	Materials & Supplies	$ -	0.03579	
25	Vehicle Lease Payments	$ -	0.06704	
26	Prepaid Vehicle Licenses	$ -	0.00000	
27	Rents	$ -	0.07045	
28	Prepaid Rents	$ -	0.00000	
29	Palo Verde Lease	$ -	-0.21133	
30	Palo Verde S/L Gain Amort	$ -	0.00000	
31	Insurance	$ (550)	0.00000	$ -
32	Other	$ (3,112)	0.02812	$ (87)
33	Total Other O&M	$ (20,725)		$ 10,584
34	Depreciation & Amortization	$ (8,488)	0.00000	$ -
35	Amort Of Prop Losses & Reg Study Costs		0.00000	
36	Total	$ (8,488)		$ -
	Income Taxes:			
37	Current:			
38	Federal	$ 11,372	-0.05897	$ (671)
39	State	$ 2,423	-0.07443	$ (180)
40	Deferred		0.00000	
41	Total	$ 13,795		$ (851)
	Other Taxes:			
42	Property Taxes	$ (1,359)	-0.47517	$ 646
43	Sales Taxes		-0.06151	
44	Franchise Taxes		-0.10132	
45	Total	$ (1,359)		$ 646
46	Interest Expense - Synchronized	$ (1,614)	-0.15924	$ 257
47	Total	$ (27,965)		$ 10,467

Arizona Public Service Company
Cash Working Capital

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Schedule B-7
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Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No	Description	Federal Income Tax (A)	State Income Tax (B)	Total Income Tax (C)	Reference
	I. Change in Current Income Taxes				
1	Income Tax Rate	32.57%	6.94%	39.51%	Schedule A-1
2	Income Taxes at Present Rates			$ 16,731	Schedule C.1, line 11
	Adjustments to Income Tax Expense:				
3	Income Taxes at Present Rates	$ 13,792	$ 2,939	16,731	
4	Income Taxes at Proposed Rate	(2,421)	(516)	(2,937)	Schedule A-1, Col.E
5	Income Taxes Expense Adjustment	$ 11,371	$ 2,423	$ 13,794	

Line No	Description	APS Adjustment (D)	Percentage (E)	Staff Adjustment (F)
	II. Allocation for Base Fuel and Purchase Power			
	Fuel For Electric Generation:			
6	Coal	$ 45,620	-153%	$ 14,653
7	Natural Gas	$ (75,040)	252%	$ (24,102)
8	Gas Mtm And Futures	$ -		
9	Handling	$ (223)	1%	$ (72)
10	Fuel Oil	$ -		
	Nuclear:			
11	Amortization	$ 12,108	-41%	$ 3,889
12	Spent Fuel	$ -		
13	Total Nuclear Fuel			
14	Total Fuel			
15	Purchased Power	$ (17,452)	59%	$ (5,605)
16	Power Mtm	$ -		
17	Power Supply Adjuster	$ -		
18	Transmission By Others	$ 5,177	-17%	$ 1,663
19	Total Purchased Power & Transmission			
20	Total Fuel And Purchased Power	$ (29,810)	100%	$ (9,575)

Notes and Source:
Col A: APS Pro Forma Adjustment for Cash Working Capital JCL_WP9

Arizona Public Service Company
Cash Working Capital

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No	Description	Reference	Amount (A)	Amount (B)
	III. Reconciliation of Non-Fuel O&M Expense Adjustments			
1	Total Staff O&M Non-Fuel Expense adjustments	Sch C.1		$ (20,725)
	Specific to Selected Cash Working Capital Components:			
2	Payroll	C-10	$ 4,994	
3	Incentive	C-14	$ (18,930)	
4	Stock Compensation			
5	Severance (Excludes Pension)	C-12	$ (3,128)	
6	Pension and OPEB			
7	Employee Benefits			
8	Payroll Taxes			
9	Materials & Supplies			
10	Vehicle Lease Payments			
11	Prepaid Vehicle Licenses			
12	Rents			
13	Prepaid Rents			
14	Palo Verde Lease			
15	Palo Verde S/L Gain Amort			
16	Insurance	C-13	$ (550)	
17	Subtotal		$ (17,614)	$ (17,614)
18	Other			$ (3,112)

Arizona Public Service Company
Forensic Investigation of Grant-Funded Projects

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Schedule C-1
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Test Year Ended December 31, 2010

(Thousands of Dollars)

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)
1	Remove APS Expense for Forensic Investigation of Grant-Funded Projects	$ (2,129)	$ (2,057)

Notes and Source

		Total Company (C)	ACC Jurisdicitonal (D)
	Company Recorded Operating Expense for Forensic Investigation		
2	IES project expenses	$ 2,334	
3	SNG project expenses	$ 503	
4	Lega/Audit expemses	$ 292	
5	APS Pro forma Adjustment	$ (1,000)	
6	Remaining Expense To Be Removed	$ 2,129	$ 2,057

Col C: APS response to STF 9.2
Col D: APS' October 26, 2011 Update Filing, Schedule C-2, page 12, APS Adjustment No 34. "Exclude ARRA Project Expenses"

Arizona Public Service Company
General Advertising Expense

Test Year Ended December 31, 2010

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Schedule C-2
Page 1 of 1

Line No.	Description	Total Company Adjustment	ACC Jurisdictional Factor	ACC Jurisdictional Adjustment
		(A)	(B)	(C)
	Adjust General Advertising Expense			
1	Remove Breakfast at the Zoo	$ (40,688)	0.906371	$ (36,878)
2	Normalize General Advertising Expense allowance	$ (590,801)	0.906371	$ (535,485)
3	Adjustment to General Advertising Expense	$ (631,489)		$ (572,363)

Notes and Source
Account 930.1

Line	General Advertising Expense Period	Reference	Amount	Adjustment		Adjusted
			(D)	(E)		(F)
4	2008	Response to Staff 21.5	$ 3,435,898			$ 3,435,898
5	2009	APS14766, page 8 and Staff 21.4	$ 1,807,823			$ 1,807,823
6	2010	APS14082 and APS14165, p.9 and Staff 21.4	$ 3,548,750	$ (40,688)	[A]	$ 3,508,062
7	2011 budget	Staff 21.5 and Staff 27.10				$ 2,059,000
7	Three-Year Average, 2008-2010					$ 2,917,261
8	APS proposed without Breakfast at the Zoo					$ 3,508,062
9	Adjustment to normalize General Advertising Expense allowance					$ (590,801)
10	Four-Year Average, 2008-2011					$ 2,702,696
11	APS proposed without Breakfast at the Zoo					$ 3,508,062
12	Adjustment to normalize General Advertising Expense allowance					$ (805,366)

Other Comparable Information

Line	Period	Reference		Allowance Compared with Budget: Amount	Percent
13	2011 YTD 6/30	APS14165, page 9 of 9	$ 1,028,946		
14		Annualized	$ 2,057,892		
15	2011 budget	Staff 21.5	$ 2,059,000	$ 858,261	41.7%
16	Four-Year Average, 2008-2011		$ 2,702,696	$ 214,565	7.9%

Line	Period	Reference	Annual	Monthly
17	2011 budget	Staff 27.10; APS14964, page 1 of 1	$ 2,059,000	$171,583.33
18	2011 YTD 9/30	Staff 27.10; APS14964, page 1 of 1	$ 1,406,210	
19		Annualized	$ 1,874,947	

[A] *Pre-filed 1.40, APS14082 and response to Staff 21.1*

Col.B: ACC Jurisdictional Factor
Adminstrative and General:

Line	Description	Amount	Source
20	ACC Jurisdictional	$ 195,988,517	AP_WP1
21	Electric Total	$ 216,234,381	AP_WP1
22	ACC Jurisdictional Factor	0.906371	

Arizona Public Service Company
Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-3
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS Original Filing (A)	Per Staff (B)	Staff Adjustment (C)
	I. Full Cash Value			
1	Plant in Service	$ 7,874,172	$ 7,870,683	
2	Environmental	$ 22,009	$ 22,009	
3	Renewable Energy Equipment	$ 4,632	$ 4,632	
4	Total	$ 7,900,813	$ 7,897,324	
	II. Assessed Value			
5	Assessment Ratio	20%	20%	
6	Plant in Service	1,574,834	1,574,137	
7	Environmental	4,402	4,402	
8	Renewable Energy Equipment	926	926	
9	Total	1,580,163	1,579,465	
	III. Estimated Property Taxes			
10	Property Tax Rate	9.00%	8.96%	
11	Plant in Service	141,735	141,043	
12	Environmental	396	394	
13	Renewable Energy Equipment	83	83	
14	Total Estimated Property Taxes	142,215	141,520	
15	Arizona Property Tax Expense for 2010	124,244	124,244	
16	Total Property Tax Expense Increase	17,971	17,276	$ (695)
	IV. Jurisdictional Expense Adjustment			
17	ACC Jurisdictional Property Tax Expense Adjustment	$ 15,115	$ 14,531	$ (584)

Notes and Source
Col.A: APS workpaper JCL_WP26, page 4 of 5
Line 15&16: APS workpaper JCL_WP26, page 2 of 5
Col.B: APS October 26, 2011 Update, APS14932, page 4 of 5
Line 15&16: APS14935, page 2 of 5; workpaper JCL_WP26 updated, page 2 of 5
Line 17, Col.A: APS' original filing, Schedule C-2, APS adjustment 14
Line 17, Col.B: APS' October 26, 2011 updated filing, Schedule C-2, APS adjustment 14 revised

Arizona Public Service Company
Solar Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-4
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (B)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Plant Additions	$ 267,979	$ 232,573	$ (35,406)
2	Less: land	$ (5,017)	$ (4,755)	
3	Depreciable Solar Plant	$ 262,962	$ 227,818	
4	Depreciation Rate	3.33%	3.33%	
5	Adjustment to Depreciation Expense	8,757	7,586	(1,170)
	II. Property Taxes			
6	ACC Jurisdictional Post Test Year Plant Additions	267,979	232,573	
7	Less: AFUDC	$ (5,735)	$ (5,735)	
8	Subtotal	262,244	226,838	
9	Assessment Ratio	20%	20%	
10	Subtotal	52,449	45,368	
11	Renewable Benefits	20%	20%	
12	Total Taxable Value	10,490	9,074	
13	Property Tax Rate	9.00%	8.96%	
14	Property Tax Expense Adjustment	944	813	(131)

Notes and Source
Col A: APS Company witness Jeffrey B Guldner Schedule JBG_WP1
Cols A and B, Line 1: See Schedule B-1
Col.B, line 13: APS14932, page 4 of 5
Col. C: Col.B-Col.A

Arizona Public Service Company
Fossil Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-5
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (B)	Staff Adjustment (C)
	I. Depreciation Expense			
1	Jurisdictional Fossil Plant Additions	$ 150,956	$ 127,498	$ (23,458)
2	ACC Jurisdictional Post Test Year Steam Production Plant Additions	$ 66,421	$ 56,099	
2	ACC Jurisdictional Post Test Year Other Production Plant Additions	$ 84,535	$ 71,399	
3	Fossil Plant Additions	$ 150,956	$ 127,498	
4	Depreciation Rate for Steam Production Plant	2.84%	2.84%	
5	Depreciation Rate for Other Production Plant	2.62%	2.62%	-
6	Annual Steam Depreciation	$ 1,886	$ 1,593	
7	Annual Other Production Depreciation	$ 2,215	$ 1,871	
8	Total Fossil Depreciation Expense Adjustment	$ 4,101	$ 3,464	$ (637)
	II. Property Taxes			
9	ACC Jurisdictional Post Test Year Steam ProductionPlant Additions	$ 66,421	$ 56,099	
10	ACC Jurisdictional Post Test Year Other ProductionPlant Additions	$ 84,535	$ 71,399	
11	Total Fossil Plant Additions	$ 150,956	$ 127,498	
12	Full Cash Value Steam	$ 22,583	$ 19,074	
13	Full Cash Value Other Production	$ 28,404	$ 23,990	
14	Total Full Cash Value for Fossil	$ 50,987	$ 43,064	
15	2010 Assessment Ratio	20%	20%	
16	Assessed Value Steam	4,517	3,815	
17	Assessed Value Other Production	$ 5,681	$ 4,798	
18	Total Assessed Value for Fossil	$ 10,197	$ 8,613	
19	Property Tax Rate	9.00%	8.96%	
20	Property Tax Expense Adjustment	$ 918	$ 772	$ (146)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Col.B, lines 1, 3 and 11: Schedule B-2
Col.B, line 19: APS14932, page 4 of 5
Col.C = Col.B-Col.A

Arizona Public Service Company
Nuclear Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-6
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (C)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Nuclear Plant Additions	$ 116,019	$ 98,483	$ (17,536)
2	Depreciation Rate for Nuclear Plant	1.44%	1.44%	
3	Annual Nuclear Plant Depreciation	$ 1,671	$ 1,418	$ (253)
	II. Property Taxes			
4	ACC Jurisdictional Post Test Year Nuclear Plant Additions	$ 116,019	$ 98,483	
5	Full Cash Value Nuclear	$ 39,446	$ 33,484	
6	2010 Assessment Ratio	20%	20%	
7	Total Assessed Value for Nuclear	$ 7,889	$ 6,697	
8	Property Tax Rate	9.00%	8.96%	
9	Property Tax Expense Adjustment	$ 710	$ 600	$ (110)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Cols A and B, Line 1: See Schedule B-3
Col.B, line 8: APS14932, page 4 of 5

Arizona Public Service Company
Distribution and General and Intangible Post Test Year Plant Depreciation and Property Tax Expense

Docket No. E-01345A-11-0224
Schedule C-7
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Per APS (A)	Per Staff (C)	Staff Adjustment (C)
	I. Depreciation Expense			
1	ACC Jurisdictional Post Test Year Distribution Plant Additions	$ 326,411	$ 285,450	$ (40,961)
2	ACC Jurisdictional Post Test Year Other General and Intangible Plant Additions	$ 97,499	$ 85,264	$ (12,235)
3	Depreciable Distribution and General and Intangible Plant	$ 423,910	$ 370,714	$ (53,196)
4	Depreciation Rate for Distribution Plant	2.37%	2.37%	
5	Depreciation Rate for General and Intangible Plant	5.90%	5.90%	-
6	Annual Distribution Depreciation	$ 7,736	$ 6,765	
7	Annual General and Intangible Depreciation	$ 5,752	$ 5,031	
8	Total Fossil Depreciation Expense Adjustment	$ 13,488	$ 11,796	$ (1,693)
	II. Property Taxes			
9	ACC Jurisdictional Post Test Year Distribution Plant Additions	$ 326,411	$ 285,450	
10	ACC Jurisdictional Post Test Year Other General and Intangible Plant Additions	$ 97,499	$ 85,264	
11	Total Fossil Plant Additions	$ 423,910	$ 370,714	
12	Full Cash Value Distribution	$ 322,543	$ 282,067	
13	Full Cash Value General and Intangible	$ 94,623	$ 82,749	
14	Total Full Cash Value for Distribution and General and Intangible	$ 417,166	$ 364,816	
15	2010 Assessment Ratio	20%	20%	
16	Assessed Value Distribution	$ 64,509	$ 56,413	
17	Assessed Value General and Intangible	$ 18,925	$ 16,550	
18	Total Assessed Value for Distribution and General and Intangible	$ 83,433	$ 72,963	
19	Property Tax Rate	9.00%	8.96%	
20	Property Tax Expense Adjustment	$ 7,509	$ 6,538	$ (971)

Notes and Source
Col A: APS Company witness Jason La Benz Schedule JCL_WP21
Col B lines 3 and 11: See Schedule B-4
Col.B, line 19: APS14932, page 4 of 5

Arizona Public Service Company
Interest Synchronization

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	ACC Jurisdictional Amount	Reference
1	Adjusted rate base	$ 5,662,998	Schedule B
2	Weighted cost of debt	2.94%	Schedule D
3	Synchronized interest deduction	$ 166,492	Line 1 x Line 2
4	Synchronized interest deduction per APS' filing	$ 168,106	See note below
5	Difference (decreased) increased interest deduction	$ (1,614)	Line 3 - Line 4
6	Combined federal and state income tax rates	39.51%	APS Sch. C-3
7	Increase (decrease) to income tax expense	$ 638	

Notes and Source

Line 4:

8	APS Adjusted Rate Base	$ 5,720,277	Schedule B
9	APS Weighted Cost of Debt	2.94%	Schedule D
10	Synchronized interest deduction per APS	$ 168,106	

Arizona Public Service Company
Base Fuel and Purchased Power

Test Year Ended December 31, 2010

Line No.	Description	Total Company Amount (A)	ACC Jurisdictional Amount (B)	Reference
1	Adjustment to Base Fuel and Purchased Power	$ (9,575)	$ (9,575)	A

Notes and Source
A: Per APS Witness Ewen Attachment PME-4 and APS' supplemental response to Staff 22.9, as shown below:

Line No.	Description	Per APS (C)	Per Staff (D)	Adjustment (E)	With Four Corners 4&5 Net Fuel Savings (F)
	Adjusted Test Year Fuel and Purchased Power Costs (cents per kWh)				
2	Normalized Fuel and Purchased Costs	3.2415	3.2071	$ (0.0344)	3.0943
3	Test Year Fuel and Purchased Power Costs	3.3486	3.3486	$ -	3.3486
4	Difference	(0.1071)	(0.1415)	$ (0.0344)	(0.2543)
	Adjusted Test Year Retail Sales (MWh)				
5	Test Year Retail Sales (MWh)	27,709,463	27,709,463		27,709,463
6	Pro Forma Adjustment to Normalize Weather	116,749	116,749		116,749
7	Pro Forma Adjustment to Annualize 12/31/07 Customer Level	7,544	7,544		7,544
8	Adjusted Test Year Retail Sales	27,833,756	27,833,756		27,833,756
9	Pro Forma Adjustment to Fuel and Purchased Power Expense	$ (29,810)	$ (39,385)	$ (9,575)	$ (70,781)
10	Incremental Fuel Cost (savings) APS estimates with Four Corners 4&5 acquisition				$ (31,396)

Col. D, Line 2: APS Supplemental Response to STF 22.9 Updates on APS Attachment PME-3, page 2 of 4.
Col. F, Line 2: APS Supplemental Response to STF 22.9 Updates on APS Attachment PME-3, page 3 of 4. This includes the net fuels savings effects that APS projects if it acquires Southern California Edison's share of Four Corners 4 and 5

Arizona Public Services
Payroll Expense

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Schedule C-10
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	APS Original Filing O&M Expense Change (A)	APS Update Filing O&M Expense Change (B)	Staff Adjustment (C)
1	Payroll Expense for Total Company	$ (519)	$ 4,855	$ 5,374
2	Payroll Expense for ACC Jurisdictional	$ (482)	$ 4,512	$ 4,994

Notes and Source:
Col A, lines 1 and 2: APS original Company Filing Schedule C-2, page 4 of 12
Col B, line 1 and 2: APS Oct 26 2011 Update Company Filing APS14944, page 4 of 12:

	Component	APS Original Filing O&M Expense (A)	APS Update Filing O&M Expense (B)	Total Change (C)	Change From Results of New Union Contract (D)	Change From APS Corrections (E)
3	Wage Change to March 2011	$ 10,173	$ 11,316	$ 1,143		$ 1,143
4	Union 387 Increase (1%) - APS' original filing	$ 783		$ (783)	$ (783)	
5	Union 387 Increase (1.5%) - APS' update		$ 1,107	$ 1,107	$ 1,107	
6	Union 387 Increase (2.5%) - APS' update		$ 1,872	$ 1,872	$ 1,872	
7	Employee Change to March 2011	$ (11,475)	$ (9,440)	$ 2,035		$ 2,035
8	Total	$ (519)	$ 4,855	$ 5,374	$ 2,196	$ 3,178

Col A, lines 3 to 8: APS Company witness Jason C La Benz Workpaper JCL_WP23, page 2 of 10
Col B, lines 3 to 8: APS Oct 26 2011 Update Company Filing APS14945, page 2 of 10
Col.E: APS' response to data request Staff 32.1 describes the error discovered by APS when updating its payroll adjustment for the new union wage contract. APS' original pro forma mistakenly included as base pay the selling of paid time off and paid earned and accrued vacation, which resulted in overstating the actual test year base payroll and understating the net impact of the annualization adjustment.

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Schedule C-11
Page 1 of 1

Arizona Public Service Company
Depreciation Expense - New Depreciation Rates

Test Year Ended December 31, 2010

Line No.	Description	Account (A)	Original Cost as of 12/31/2010 (B)	Depreciation Rate per Decision No. 71448 (C)	Depreciation Expense (D)	Reference
	I. Account 370.01, Electronic Meters					
1	Meters Plant Account	370.01	$ 62,207,543	3.68%	$ 2,289,238	A
2	APS Depreciation Accrual				$ 3,863,088	A
3	Adjustment to Restore Meters to Currently Authorized Depreciation Rate				$ (1,573,850)	
4	ACC Jurisdictional Allocation Factor				0.993900	B
5	ACC Jurisdictional Adjustment to Depreciation Expense				$ (1,564,250)	
	II. Account 370.03, AMI Meters					
6	Meters Plant Account	370.03	$ 117,715,566	3.82%	$ 4,496,735	
7	APS Depreciation Accrual				$ 7,686,826	
8	Adjustment to Restore Meters to Currently Authorized Depreciation Rate				$ (3,190,091)	
9	ACC Jurisdictional Allocation Factor				0.993900	B
10	ACC Jurisdictional Adjustment to Depreciation Expense				$ (3,170,631)	
	III. Summary of ACC Jurisdictional Adjustment for Meters Depreciation Expense					
11	Depreciation Expense for Account 370.01, Electronic Meters				$ (1,564,250)	
12	Depreciation Expense for Account 370.03, AMI Meters				$ (3,170,631)	
13	Total Adjustment for Meters Depreciation Expense				$ (4,734,881)	

Notes and Source
A: APS workpaper JCL_WP17, page 4
B: ACC jurisdictional allocation factor CUST370 from Company Schedule G-7, page 2, line 18

Line No.	Description	Original Plant Cost @ 12/31/2010 (E)	Accumulated Depreciation at 12/31/2010 (F)	Net Plant Balance (G)	Currently Authorized Depreciation Rate (H)	Depreciation Expense (I)	Increase Dollars (J)	Increase Percent (K)
	Using Recorded Depreciation Reserve							
14	Electronic Meters - Plant Account 370.01	$ 62,207,543	$ (19,681,616)	$ 42,525,927	3.68%	$ 2,289,238		
15	AMI Meters - Plant Account 370.03	$ 117,715,566	$ (5,454,950)	$ 112,260,616	3.82%	$ 4,496,735		
16	Total Meters	$ 179,923,109	$ (25,136,566)	$ 154,786,543		$ 6,785,973		
					APS Proposed Depreciation Rate			
	Using APS Proposed Redistributed Reserve							
17	Electronic Meters - Plant Account 370.01	$ 62,207,543	$ (16,047,329)	$ 46,160,214	6.21%	$ 3,863,088	$ 1,573,850	68.7%
18	AMI Meters - Plant Account 370.03	$ 117,715,566	$ (9,009,526)	$ 108,706,040	6.53%	$ 7,686,826	$ 3,190,091	70.9%
19	Total Meters	$ 179,923,109	$ (25,056,855)	$ 154,866,254		$ 11,549,914	$ 4,763,941	70.2%

Cols. E and F: Plant and Accumulated Depreciation amounts from Attachment REW-2, Statement D filed in conjunction with Dr. White's Direct Testimony
Statement C, page 36, shows Plant and recorded and redistributed reserves
Statement A, page 18, shows *currently* authorized and APS-proposed depreciation rates

Arizona Public Service Company
Prospective Amortization of 2010 Severance Costs

Test Year Ended December 31, 2010

Docket No. E-01345A-11-0224
Schedule C-12
Page 1 of 1

Line No.	Description	Total Company (A)	ACC Jurisdictional (B)
1	Severance Costs Adjustment	$ (3,366)	$ (3,128)

Notes and Source
Per APS Company Severance Costs Adjustment:

Line No.	Description	Per Company Total Company	Per Company ACC Jurisdictional	Per Staff Total Company	Per Staff ACC Jurisdictional
2	Net Test Year Expense (Note A)	$ 10,099	$ 9,384	$ 10,099	$ 9,384
3	Amortization (Notes B and C)	$ 3,366	$ 3,128		
4	Adjustment	$ (6,733)	$ (6,256)	$ (10,099)	$ (9,384)

[A] APS recorded the severance cost as expense in the 2010 test year
[B] APS proposes to amortize this projectively for ratemaking purposes, using a three-year amortization
[C] Staff recommends that the amortization of the severance cost commence when the associated savings commenced. Based on that, there should be no amount remaining to be prospectively amortized when new base rates go into effect for APS as a result of this rate case.

Arizona Public Service Company
Directors and Officers Liability Insurance Expense

Docket No. E-01345A-11-0224
Schedule C-13
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	FERC Account	Total Company (A)	ACC Jurisdictional (B)
1	Remove Half of D&O Insurance Expense	925	$ (585)	$ (550)

Notes and Source
Cols A and B: APS response to STF 21.6

2	Directors and Officers Liability Insurance Expense	925	$ 1,170	$ 1,099
3	50% of D&O Expense		$ 585	$ 550

Arizona Public Service Company
Incentive Compensation

Docket No. E-01345A-11-0224
Schedule C-14
Page 1 of 1

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Staff Jurisdictional Expense Adjustment (A)	Reference
1	Adjustment for Allowance for 50% of a Normalized Amount of Incentive Compensation Expense	$ (18,930)	Line 22, below
2	Allowance for 50% of a Normalized Amount of Incentive Compensation Expense	$ 14,030	Line 19, Col.I

Notes and Source
Cols B through G: APS response to STF 22.2

Line	Account	Total Company 2008 (B)	Total Company 2009 (C)	Total Company 2010 (D)	ACC Jurisdictional 2008 (E)	ACC Jurisdictional 2009 (F)	ACC Jurisdictional 2010 (G)
		[BEGIN CONFIDENTIAL]					
3	506	[redacted]					
4	519						
5	524						
6	528						
7	546						
8	549						
9	557						
10	266						
11	588						
12	903						
13	916						
14	920						
15	928						
16	930						
17	Total						
							[END CONFIDENTIAL]

Line	Description	Total Company (H)	ACC Jurisdictional (I)	
18	3 Year Average	$ 30,194	$ 28,059	
19	Expense Allowance Based on 50% of Normalized Amount	$ 15,097	$ 14,030	
20	Adjustment from 2010 Expense to 3 Year Average	$ (5,273)	$ (4,900)	
21	50% of 3 Year Average Expense	(15,097)	(14,030)	
22	Total Adjustment to Incentive Compensation Expense	$ (20,370)	$ (18,930)	$ (18,930)
23	Expense Allowance Based on 50% of Normalized Amount	Sum of Col.G, lines 16 and 20		$ 14,030

Docket No. E-01345A-11-0224
Schedule C-15
Page 1 of 1

Arizona Public Services
Normalization of Fossil Non-Plant Maintenance Expense
ACC Jurisdictional

Test Year Ended December 31, 2010
(Thousands of Dollars)

Line No.	Description	Test Year at 12/31/2010 (A)	Normalized Per APS (B)	Normalized Per Staff (C)	APS Adjustment (D)	Staff Adjustment (E)	Net Staff Adjustment (F)
1	Maintenance Expense for Total Company	$ 116	$ 882	$ 609	$ 766	$ 493	$ (273)
2	Maintenance Expense for ACC						$ (266)

Notes and Source:
Col A: APS witness Jason C La Benz Workpaper JCL_WP30 Page 5 of 63
Col.B and C: See columns M and N, respectively:

Line No.	Description	2005 (G)	2006 (H)	2007 (I)	2008 (J)	2009 (K)	2010 (L)	Normalized Per APS (Avg of 2005 - 2010) (M)	Normalized Per Staff (Avg of 2006-2010) (N)
3	Routine Maintenance	$ 2,246	$ 999	$ 660	$ 495	$ 773	$ 116	$ 882	$ 609
4	Overhaul	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Total Normalized Expense	$ 2,246	$ 999	$ 660	$ 495	$ 773	$ 116	$ 882	$ 609
6	Dollar increase over 2010 recorded							$ 766	$ 493
7	Percentage increase over 2010 recorded							660%	425%

Line No.	Description	
8	APS Fossil Maintenance Adjustment for Total Company	$ (4,397)
9	APS Fossil Maintenance Adjustment for ACC	$ (4,290)
10	ACC Jurisdictional Percentage	97.57%

Lines 3 to 5 for year 2005 to 2010 data are from APS witness Jason C La Benz Workpaper JCL_WP30 Page 5 of 63
Lines 8 and 9 data are from APS witness Jason C La Benz Workpaper JCL_WP30 Page 1 of 63

Arizona Public Service Company
Normalize Fossil Maintenance Expense

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Schedule C-15
Page 2 of 2

Test Year Ended December 31, 2010
(Thousands of Dollars)

APS Fossil Maintenance Expense Adjustment:

Line		OVERHAUL			ROUTINE MAINTENANCE			TOTAL MAINTENANCE		
No.	Operating Unit	Normal	Test Year	Pro-Forma	Normal	Test Year	Pro-Forma	Normal	Test Year	Pro-Forma
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	Cholla 1	2,239	38	2,201	1,583	1,763	1,763	3,822	1,801	2,021
2	Cholla 2	3,053	8,041	(4,988)	4,327	2,016	2,016	7,380	10,057	(2,677)
3	Cholla 3	2,310	0	2,310	1,628	2,325	2,325	3,938	2,325	1,613
4	Cholla Common	10	0	10	4,641	4,084	4,084	4,651	4,084	567
5	Four Corners 1	2,324	472	1,852	2,761	2,433	2,433	5,085	2,905	2,180
6	Four Corners 2	2,387	7,092	(4,705)	2,756	2,398	2,398	5,143	9,490	(4,347)
7	Four Corners 3	3,291	0	3,291	3,256	3,244	3,244	6,547	3,244	3,303
8	Four Corners 4	842	3,516	(2,674)	1,261	1,352	1,352	2,103	4,868	(2,765)
9	Four Corners 5	744	6	738	1,234	975	975	1,978	981	997
10	Four Corners Common	0	0	0	1,903	1,862	1,862	1,903	1,862	41
11	Navajo 1, 2, 3	2,853	5,324	(2,471)	4,780	3,448	3,448	7,633	8,772	(1,139)
12	Ocotillo Steam 1	193	135	58	400	151	151	593	286	307
13	Ocotillo Steam 2	98	66	32	248	129	129	346	195	151
14	Ocotillo Steam Common	19	16	3	342	428	428	361	444	(83)
15	Ocotillo CT 1	58	145	(87)	35	48	48	93	193	(100)
16	Ocotillo CT 2	7	6	1	21	34	34	28	40	(12)
17	Ocotillo CT Common	0	0	0	0	0	0	0	0	0
18	Ocotillo Common	15	9	6	197	197	197	212	206	6
19	Redhawk CC 1	3,536	12,862	(9,326)	2,742	2,320	2,320	6,278	15,182	(8,904)
20	Redhawk CC 2	3,118	1,369	1,750	2,781	2,291	2,291	5,899	3,660	2,240
21	Douglas CT	9	10	(1)	41	46	46	50	56	(6)
22	Saguaro Steam 1	26	4	22	36	28	28	62	32	30
23	Saguaro Steam 2	20	1	19	71	27	27	91	28	63
24	Saguaro Steam Common	0	0	0	112	97	97	112	97	15
25	Saguaro CT 1	6	15	(9)	13	20	20	19	35	(16)
26	Saguaro CT 2	6	20	(14)	21	22	22	27	42	(15)
27	Saguaro CT 3	2	1	1	186	166	166	188	167	21
28	Saguaro CT Common	0	0	0	5	1	1	5	1	4
29	Saguaro Common	0	0	0	304	308	308	304	308	(4)
30	Sundance CT1 - CT10	1,099	1,609	(510)	452	831	831	1,551	2,440	(889)
31	West Phoenix CC 1	82	0	82	802	258	258	884	258	626
32	West Phoenix CC 2	376	1	375	303	94	94	679	95	584
33	West Phoenix CC 3	221	0	221	267	133	133	488	133	355
34	West Phoenix CC 4	454	157	297	661	455	455	1,115	612	503
35	West Phoenix CC 5	2,452	2,456	(4)	2,146	2,017	2,017	4,598	4,473	125
36	West Phoenix CC Commo	0	0	0	143	301	301	143	301	(158)
37	West Phoenix CT 1	2	0	2	113	58	58	115	58	57
38	West Phoenix CT 2	2	12	(10)	36	100	100	38	112	(74)
39	West Phoenix CT Commo	0	0	0	(29)	3	3	(29)	3	(32)
40	West Phoenix Common	0	0	0	968	934	934	968	934	34
41	Yucca CT 1	31	0	31	2	(63)	(63)	33	(63)	96
42	Yucca CT 2	31	0	31	6	(3)	(3)	37	(3)	40
43	Yucca CT 3	23	0	23	(4)	(171)	(171)	19	(171)	190
44	Yucca CT 4	7	0	7	9	(10)	(10)	16	(10)	26
45	Yucca CT 5	0	0	0	9	29	29	9	29	(20)
46	Yucca CT 6	0	0	0	8	21	21	8	21	(13)
47	Yucca 5-6 Common	0	0	0	19	86	86	19	86	(67)
48	Yucca CT Common	0	0	0	7	10	10	7	10	(3)
49	Yucca Common	0	0	0	51	84	84	51	84	(33)
50	Fossil Non-Plant	0	0	0	881	116	116	881	116	765
51	**Total Fossil**	31,946	43,382	(11,436)	44,535	37,496	7,039	76,481	80,878	(4,397)
52	ACC Fossil									$ (4,290)

Notes and Source:

Data are from APS Income Statement Pro Forma Adjustment for Normalized Fossil Maintenance Expense JCL_WP30

Amounts in the "normal" columns are based on a six-year average of "time adjusted dollars".

Subtotals for Four Corners Plant maintenance are shown below:

		APS Proposed			APS Proposed			APS Proposed		
53	Four Corners Units 1-3	8,002	7,564	438	8,773	8,075	8,075	16,775	15,639	1,136
54	Four Corners Units 4&5	1,586	3,522	(1,936)	2,495	2,327	2,327	4,081	5,849	(1,768)
55	Four Corners Common	0	0	0	1,903	1,862	1,862	1,903	1,862	41
56	Four Corners Total	9,588	11,086	(1,498)	13,171	12,264	12,264	22,759	23,350	(591)

Arizona Public Services
Edison Electric Institute Dues

Test Year Ended December 31, 2010

Line No.	Description	Total Company Test Year (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment Total Co. (D)	ACC Jurisdictional Allocation Factor (E)	ACC Jurisdictional Amount (F)
1	Regular Activities of EEI	$ 678,611	$ (108,578)	$ 570,033	$ (230,252) a	0.939290	$ (216,273)

Notes and Source
Cols A, B and C: Per APS' response to Staff 1.36
a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

Line		Staff Adjustment	
2	EEI Regular Activities Dues	$ 678,611	
3	Regular Dues disallowance percentage	49.93%	See page 2
4	Staff total adjustment to Regular Dues	$ (338,830)	
5	Less: Company adjustment	$ (108,578)	
6	Staff adjustment to APS' Adjusted Regular Dues	$ (230,252)	

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance
1	Legislative Advocacy	20.38%	20.38%
2	Legislative Policy Research	6.02%	
3	Regulatory Advocacy	16.49%	16.49%
4	Regulatory Policy Research	13.99%	
5	Advertising	1.67%	1.67%
6	Marketing	3.68%	3.68%
7	Utility Operations and Engineering	11.31%	
8	Finance, Legal, Planning and Customer Service	18.75%	
9	Public Relations	7.71%	7.71%
10	Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-3
Copies of APS' Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Staff 6.55 Supplemental	Post test year plant pro forma reflecting actual information through July 31, 2011 (without voluminous and/or confidential attachments)	No	1	2
Staff 27.2	Post test year plant actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	3
Staff 27.8	Accumulated Depreciation actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	4
Staff 27.9	Post test year ADIT actual amounts will be available 30 days after the close of the respective quarterly accounting period	No	1	5
Staff 25.11	Uncollectibles factor for years 2008-2010	No	3	6 - 8
Staff 27.4	Post test year plant	No	3	9 - 11
Staff 22.7	Post test year CWIP with expected in-service timing	No	2	12 - 13
Staff 27.13	Post test year CWIP with expected in-service timing	No	2	14 - 15
Staff 27.6	Accumulated Depreciation	No	1	16
Staff 15.13	ADIT impact from bonus depreciation relating to post test year plant	No	5	17 - 21
AECC 1.11	Bonus depreciation and its impact on ADIT	No	5	22 - 26
Staff 20.1	Estimated jurisdictional ADIT (Actuals: 7/31/11 - 8/31/11; Forecast: 9/30/11 - 3/31/12)	No	2	27 - 28
Staff 9.2	APS is not including costs related to IES or SNG; Removal of costs related to forensic investigation of DOE grant-funded plant (without voluminous attachments)	No	1	29
Staff 9.3	Removal of expenses related to SNG and DOE reimbursements and liability	No	1	30
Staff 20.2	Explanation of how project expenditures and related government reimbursements in 2010 are accounted	No	1	31
Staff 20.3	Grant funded projects are not included in plant additions or post test year plant	No	1	32
Prefiled 1.40	Itemization of test year advertising expense	No	2	33 - 34
Staff 21.1	APS advertising (without voluminous attachments)	No	2	35 - 36
Staff 21.3	Trial Balance of advertising expense for fiscal year 2011 through September	No	2	37 - 38
Staff 21.4	Explanation of why 2010 general advertising expense was higher than 2009	No	1	39
Staff 21.5	Advertising expense (actual for 2008 and budgeted for 2011)	No	1	40
Staff 27.10	Breakfast at the Zoo expense; Budget for advertising expense (without voluminous attachments)	No	2	41 - 42
Staff 32.1	Explanation of the error corrections made to the original APS payroll annualization adjustment	No	2	43 - 44
	Response to data request 12.27 from Docket No. E-01345A-08-0172 regarding meter addition investments for 2008-2009	No	2	45 - 46
	Response to data request 17.7 from Docket No. E-01345A-08-0172 regarding depreciation rates from 1998 through the present (without attachment)	No	2	47 - 48
TEP Exhibit KAK-1	Tucson Electric Power Company - Docket No. E-01933A-07-0402 - Dr. Kateregga 2007 Depreciation Rate Study for TEP - meter related depreciation rate information	No	3	49 - 51
UNSE Exhibit REW-2	UNS Electric, Inc. - Docket No. E-04204A-06-0783 - Dr. White 2006 Depreciation Rate Review for UNSE - meter related depreciation rate information	No	3	52 - 54
UNSE Attachment REW-2	UNS Electric, Inc. - Docket No. E-04204A-09-0206 - Dr. White 2009 Technical Update for UNSE - meter related depreciation rate information	No	5	58 - 62
APS Attachment REW-1	APS - Docket No. E-01345A-08-0172 - Dr. White 2008 Depreciation Rate Study for APS - meter related depreciation rate information	No	3	55 - 57
Staff 25.8	APS' request for prospective 3-year amortization of 2010 non-voluntary severance program expense	No	1	63
Staff 25.6	APS' request for a portion of the non-voluntary severance program expense to remain in the test year (without attachments)	No	1	64
Staff 25.5	Request for accounting deferrals or to establish a regulatory asset for the non-voluntary severance program expense was not made by APS; Net employee reduction amount as a result of voluntary and non-voluntary terminations; explanation of how the amount of first year savings was attained; the amount of total savings related to O&M and capital savings (without voluminous attachments)	No	3	65 - 67
Staff 21.6	Directors and Officers liability insurance is expensed as incurred with no prepaid asset account	No	2	68 - 69
Staff 19.17	Amount of incentive compensation charged to O&M for years 2005 - 2007 (without voluminous attachments)	No	4	70 - 73
Staff 25.21	Cause of fossil non-plant maintenance cost differential in 2005 compared to other years	No	1	74
Staff 27.11	Summary of APS' proposed ratemaking treatment of Four Corners; remaining net book value of the Four Corners assets	No	2	75 - 76
Staff 25.22	Normal overhaul and maintenance expense will end after a fossil unit is retired; proposed deferral order regarding Four Corners maintenance costs is pending in another docket	No	2	77 - 78
Staff 1.36	Removal of percentage of EEI dues (includes APS14209 excerpt)	No	2	79 - 80
Staff 22.5	APS did not provided requested EEI budget of financial information by NARUC category	No	1	81
Staff 27.7	Jurisdictional ADIT amounts for March 31, 2012	No	1	82
Staff 15.7	Estimated ADIT (actual: 7/31/11 - 8/31/11; Forecast: 9/30/11 - 3/31/12)	No	2	83 - 84
Staff 22.9 supplemental	Revised forecast of base cost of fuel (without voluminous attachments)	No	2	85 - 86
	Total Pages Including this Page		86	

ARIZONA CORPORATION COMMISSION
STAFF'S SIXTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
AUGUST 10, 2011

Staff 6.55: **DIRECT TESTIMONY OF M.A. SCHIAVONI: Re: Attachment MAS-1.** Please update the projected closed cost and estimated in-Service Date for the listed projects and/or work items. Please confirm that the various line items indicating in-Service prior to July 31, 2011 were, in fact, put in-service at the closed costs indicated or edit the listing to indicate that the dates and/or costs were otherwise.

Response: *Pursuant to discussions with ACC Commission Staff,* the Company will update the capital project information for each of the Post Test Year Plant pro formas (Fossil Generation, Nuclear Generation, Distribution and General and Intangible Plant, and Solar Generation) with actual data through August 31, 2011. This information will be provided to all intervening parties no later than September 20, 2011.

Supplemental Response 9/22/2011: Attached are the following updated Post-Test Year Plant Additions pro forma adjustments using actuals through July 31, 2011:

- Solar Generation – APS14743
- Fossil Generation - APS14744
- Nuclear Generation - APS14745
- Distribution and General and Intangibles - APS14746

Supporting calculations for property taxes and depreciation expense is also attached as APS14747. Please note the information attached to the Solar Generation Post-Test Year Plant Additions is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jeff Guldner/Mark Schiavoni/Randy Edington/Daniel Froetscher/Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.2: Post test year plant.

a) When does APS expect to have actual 12/31/2011 (post test year) plant amounts available for review?

b) When does APS expect to have actual 3/31/2012 (post test year) plant amounts available for review?

c) Please provide the actual 12/31/2011 (post test year) plant amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 (post test year) plant amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded plant at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded plant at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 Post Test Year amounts available for review 30 days after the close of the year.

b) APS expects to have actual 3/31/2012 Post Test Year amounts available for review 30 days after the close of the period.

c) - (f) See (a) and (b).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.8: Accumulated Depreciation.

a) When does APS expect to have actual 12/31/2011 accumulated depreciation amounts available for review?

b) When does APS expect to have actual 3/31/2012 accumulated depreciation amounts available for review?

c) Please provide the actual 12/31/2011 accumulated depreciation amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 accumulated depreciation amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded accumulated depreciation at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded accumulated depreciation at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 accumulated depreciation available for review 30 days after the close of the year.

b) APS expects to have actual 3/31/2012 accumulated depreciation available for review 30 days after the close of the period.

c) - (f) See (a) and (b).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.9: Accumulated Deferred Income Taxes.

a) When does APS expect to have actual 12/31/2011 Accumulated Deferred Income Tax amounts available for review?

b) When does APS expect to have actual 3/31/2012 Accumulated Deferred Income Tax amounts available for review?

c) Please provide the actual 12/31/2011 Accumulated Deferred Income Tax amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

d) Please provide the actual 3/31/2012 Accumulated Deferred Income Tax amounts, by account, as soon as they are available, and provide the related trial balances. Reconcile the amounts of plant, by account, as of each date with the amounts on the trial balance.

e) Please identify the amounts of recorded Accumulated Deferred Income Tax at 3/31/2012 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

f) Please identify the amounts of recorded Accumulated Deferred Income Tax at 12/31/2011 that corresponds to the West Phoenix disallowance amount at 12/31/2010 in APS' proposed rate base adjustment for that.

Response:

a) APS expects to have actual 12/31/2011 Post Test Year Accumulated Deferred Income Tax (ADIT) amounts available 30 days after the close of the year.

b) APS expects to have actual 03/31/2012 Post Test Year ADIT amounts available for review 30 days after the close of the period.

c)-f) See (a) and (b).

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.11: Uncollectibles. Refer to APS' response to data request Prefiled 1.21, APS14067.

a. Please identify the annual revenues each year 2008, 2009 and 2010, to which the uncollectibles relate.

b. Please show an uncollectibles factor for each year 2008, 2009 and 2010.

c. Why has the uncollectibles expense in account 904 decreased from 2008 to 2009?

d. Why has the uncollectibles expense in account 904 decreased from 2000 to 2010?

e. Please reconcile the 2009 amounts shown on APS14067 with the 2009 general ledger page showing account 9040000, Uncollectible Accounts (APS14162, page 4791 of 4840). Identify, quantify and explain each reconciling item.

f. Please reconcile the 2010 amounts shown on APS14067 with the 2010 general ledger page showing account 9040000, Uncollectible Accounts (APS14048, page 5007 of 5053). Identify, quantify and explain each reconciling item.

Response: a. 2008 $2,921,679,877
2009 $2,981,308,172
2010 $2,964,091,853

b. The uncollectible factor applied to revenue for 2008, 2009 and 2010 was:
2008 0.21%
2009 0.21%
2010 0.21%

c. The decrease in uncollectibles expense from 2008 to 2009 is primarily due to an increase in the write-off reserve in 2008. The reserve was increased in September 2008 when the factor was increased from 0.16% to 0.21%. This resulted in an increase to expense of $753k in 2008.

d. APS assumes this question refers to 2009 as opposed to 2000. The decrease in uncollectibles expense from 2009 to 2010 is primarily due to a small decrease in the reserve due to the slight decrease in revenue and a reduction in uncollectible expense.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Response to Staff 25.11 Continued:	e. See APS14973, attached.
	f. See APS14973, attached.

STF25.11 e	Charge Number	Account	Budget Item	Sub Budget	Amount			
	1904-002	9040000	GEN OPS-99	BAD DEBT	$6,871,183.71	*	$6,871,183.71	
	1904-004	9040000	GEN OPS-99	BAD DEBT	$85,000.00			Power Trading Writeoff Expense
	1904-999	9040000	GEN OPS-99	UNCOL ACTS	$91,447.87	*	$91,447.87	
	99-904-001	9040000	EXPENSE-99	BAD DEBT	$3,013,989.44			Note receivable reserve
					$10,061,621.02		$6,962,631.58	

* These values summed together total $6,962,631.58 and agrees to the values refelcted on APS14067.

STF25.11 f	Charge Number	Account	Budget Item	Sub Budget	Amount			
	1904-002	9040000	GEN OPS-99	BAD DEBT	$6,777,073.68	**	$6,777,073.68	
	1904-999	9040000	GEN OPS-99	UNCOL ACTS	($24,592.24)	**	($24,592.24)	
	99-904-001	9040000	EXPENSE-99	BAD DEBT	($2,996,079.61)			Note receivable reserve reversal
					$3,756,401.83		$6,752,481.44	

** These values summed together total $6,752,481.44 and agrees to the values refelcted on APS14067.

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.4: Post test year plant, APS update in response to STF 6.55, APS14743 through APS146.

a) Please confirm that the Company's proposed post test year plant additions for solar of $260.765 million total company and $251.899 ACC jurisdictional through June 30, 2012 include $20.006 million and $19.326 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year solar plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

b) Please confirm that the Company's proposed post test year plant additions for nuclear of $111.397 million total company and $107.609 ACC jurisdictional through June 30, 2012 include $9.447 million and $9.126 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year nuclear plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

c) Please confirm that the Company's proposed post test year plant additions for coal and other fossil generation of $154.606 million total company and $149.350 ACC jurisdictional through June 30, 2012 include $22.621 million and $21.852 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year coal and other fossil generation plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

d) Please confirm that the Company's proposed post test year plant additions for distribution of $333.398 million total company and $326.411 million ACC jurisdictional through June 30, 2012 include $9.386 million and $9.160 million of additions projected for April 1, 2012 through June 30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year distribution plant additions that APS projected for the period April 1, 2012 through June 30, 2012 per the STF 6.55 update.

e) Please confirm that the Company's proposed post test year plant additions for general and intangible of $99.586 million total company and $97.499 million ACC jurisdictional through June 30, 2012 include $2.795 million and $2.736 million of additions projected for April 1, 2012 through June

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
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DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.4 Continued:

30, 2012. If this cannot be confirmed, please explain fully and identify the amount of post test year general and intangible plant additions that APS projected for the period April 1, 2012 through June 30 2012 per the STF 6.55 update.

f) Please identify the amount included in the Company's proposed post test year plant additions other than transmission for (1) total company and (2) for ACC jurisdictional through June 30, 2012 per the STF 6.55 update materials include for additions projected for April 1, 2012 through June 30, 2012 and provide supporting documentation.

Response:

(a) – (c) APS confirms these amounts.

(d) The amounts listed appear to be from the original filing. For the updated Staff 6.55 amounts please see attached, APS14974.

(e) The amounts listed appear to be from the original filing. For the updated Staff 6.55 amounts please see attached, APS14974.

(f) Please see attached, APS14974.

Witness: Jay La Benz

Staff 27.4 Docket No. E-01345A-11-0224

(000's)

	(a) Updated PTY Total Company	(b) April-June Total Company	(c) April-June ACC Jurisdiction
Solar	260,765	20,006	19,326
Nuclear	111,397	9,447	9,126
Coal and other Fossil	154,606	22,621	21,852
Distribution	330,604	40,038	40,030
G & I	92,155	4,071	3,154
Total	**949,527**	**96,183**	**93,488**

*Column (a) include the total Post Test Year amounts by function.
Colunn (b) amounts for Apr 2012 thru July 2012 are included in column (a).

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OCTOBER 14, 2011

Staff 22.7: Post test year plant based test year CWIP going into service. Refer to APS' 12-31-2010 CWIP balance is $459.316 million (per Sch E-1, line 4).

a) Please provide an itemized listing, by plant account, of the components of the 12-31-2010 CWIP balance that total to the $459.316 million.

b) Please identify each item of 12-31-2010 CWIP that had been placed into service by August 31, 2011 and provide the dollar amounts by plant account.

c) Please identify each item of 12-31-2010 CWIP that APS expects will be placed into service between September 1 and December 31, 2011 and indentify the dollar amounts for each, by plant account.

d) Please identify each item of 12-31-2010 CWIP that APS expects will be placed into service between January 1 and March 31, 2012 and indentify the dollar amounts for each, by plant account.

Response: (a)-(d) Attached as APS14913 is the requested schedule.

Witness: Jay La Benz

ARIZONA PUBLIC SERVICE COMPANY
Staff Question 22.7 (a -d)

Balance per Sch E-1 line 4	459,316,067
Less: Nuclear Fuel (account 1201)	(91,884,172)
CWIP Accruals (1071, 1072 & 1074)	1,981,183
Construction In Progress (account 107)	**369,413,078**

	(a)	(b)		(c)	(d)
Function *	Dec 2010 CWIP Balance	CWIP Jan - Aug 2011 **	Actual Additions as of Aug 2011 **	Estimated Additions Sept 1 - Dec 31 2011	Estimated Additions Jan 1 - Mar 31 2012
Intangible	27,420,972	14,896,571	17,193,632	4,206,814	425,301
Steam	33,455,051	12,918,827	19,409,029	4,224,674	4,247,363
Nuclear	86,481,939	16,817,625	18,889,236	46,334,932	700,784
Other Production	53,840,615	42,267,371	84,534,634	6,994,826	372,351
Transmission	80,606,203	18,105,616	23,318,013	6,646,014	21,517,132
Distribution	48,204,086	32,205,966	54,585,816	9,470,993	907,305
General Plant	39,404,212	23,978,893	25,531,249	12,718,312	0
	369,413,078	161,190,870	243,461,609	90,596,565	28,170,236

* CWIP balances are <u>not</u> classified into specific plant accounts until the project is in-service and unitized
** CWIP Amounts" are totals inlcuded in December balance while Actual Additions are totals of acutal dollars spent and put into service.

ARIZONA CORPORATION COMMISSION
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Staff 27.13: December 31, 2010 end-of-test-year CWIP going into service by March 31, 2012. Refer to the response to STF 22.7.

a) Does the information on APS14913 include ONLY costs that were recorded as CWIP on APS' books at December 31, 2010?

b) Does the information on APS14913 include any additional dollars charged to CWIP or Plant accounts after December 31, 2010 that were not contained in the December 31, 2010 end-of-test year CWIP balance?

c) If the answer to either part a or b is affirmative, please provide similar information that includes ONLY costs that were recorded as CWIP on APS' books at December 31, 2010 and does not include any additional dollars charged to CWIP or Plant accounts after December 31, 2010 that were not contained in the December 31, 2010 end-of-test year CWIP balance.

d) Are there any amounts for December 31, 2010 CWIP, i.e., in the $369,413,078 in column a on APS14913, that relate to projects under construction that are NOT expected to be in service by March 31, 2012? If so, please identify those amounts, preferably by function.

Response:

a) In APS14913, columns a, c, d, and b the portion labeled "CWIP Jan-Aug 2011" reflect only costs that were recorded as CWIP as of December 31,2011. The portion of Column b "Actual Additions as of Aug 2011" reflects actual plant additions for work orders that were included in the 12-31-2011 CWIP balance.

b) Yes, see response (a).

c) In APS14913, column (a) only includes costs that were booked to CWIP as of December 31, 2010. It does not include any estimated or actual dollars after December 31, 2010.

d) See column "e" in APS14970, attached.

Witness: Jay La Benz
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ARIZONA PUBLIC SERVICE COMPANY
Staff Question 27.13(a -d)

Balance per Sch E-1 line 4	459,316,067
Less: Nuclear Fuel (account 1201)	(91,884,172)
CWIP Accruals (1071, 1072 & 1074)	1,981,183
Construction In Progress (account 107)	369,413,078

	(a)	(b)	(c)	(d)	(e)
Function *	**Dec 2010 CWIP Balance**	**Actual CWIP in Service between Jan - Aug 2011**	**Estimated CWIP to go in service between Sept 1 - Dec 31 2011**	**Estimated CWIP to go into service between Jan 1 - Mar 31 2012**	**12-31-2010 CWIP Balance Not Scheduled to go into service between Jan 2011 & Mar 2012**
Intangible	27,420,972	14,896,571	4,206,814	425,301	7,892,287
Steam	33,455,051	12,918,827	4,224,674	4,247,363	12,064,187
Nuclear	86,481,939	16,817,625	46,334,932	700,784	22,628,598
Other Production	53,840,615	42,267,371	6,994,826	372,351	4,206,067
Transmission	80,606,203	18,105,616	6,646,014	21,517,132	34,337,441
Distribution	48,204,086	32,205,966	9,470,993	907,305	5,619,822
General Plant	39,404,212	23,978,893	12,718,312	0	2,707,006
	369,413,078	161,190,870	90,596,565	28,170,236	89,455,407

* CWIP balances are not classified into specific plant accounts until the project is in-service and unitized

ARIZONA CORPORATION COMMISSION
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Staff 27.6: Accumulated Depreciation. Referring to the originally filed APS adjustments for post test year plant, by type of plant, and to the updated amounts that APS provided in response to STF 6.55, please provide the Total Company and ACC Jurisdictional amounts (1) as of 3/31/2012 and (2) identify the changes APS estimated to occur for the period April 1, 2012 through June 30, 2012.

Response: (1) Please see APS's response to Staff 15.9 for the 3/31/2012 Total Company Accumulated Depreciation. The corresponding ACC jurisdiction of these amounts are as follows:

- Solar: $3.391 Million
- Fossil: $113.349 Million
- Nuclear: $94.045 Million
- Distribution and General & Intangibles: $219.674 Million

(2) For Fossil Generation, Nuclear Generation, and Distribution and General and Intangible Plant the only change in accumulated depreciation for the referenced period is continued depreciation on plant in service at 12/31/2010. Consistent with the RES treatment Solar Generation, changes for the referenced period includes book depreciation on additions during the post test year period.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
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Staff 15.13: ADIT on post test year plant additions.

a) Please identify the dollar amount of 2011 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

b) Please identify the dollar amount of 2012 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

c) Please identify the ADIT impacts from all 2011 and 2012 bonus tax depreciation related to each of the post test year Plant additions on JCL_wp8;

d) Please include supporting workpapers and calculations in Excel format for the bonus depreciation and the related ADIT impacts; and

e) Please provide the related ADIT impacts if post test year plant additions were limited to those projected to actually be in service by March 31, 2012.

Response: Inclusion of any such estimated projections of deferred taxes as a rate base offset may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

a) Please see response to AECC 1.11 (c) for an estimate of 2011 bonus depreciation related to each of the post-Test Year Plant Additions on JCL_WP8.

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated bonus deprecation tax deduction for 2011 has been modified from the estimate provided in AECC 1.11 (c) to a range of $404M - $450M, as shown at APS14831. It is anticipated that APS will be unable to fully realize this benefit in 2011 due to expected tax loss carryforwards. Only realized benefits are eligible for *normalization*.

b) Please see APS's response to AECC 1.11 (c) for an estimate of 2012 bonus depreciation related to each of the post test year Plant additions on JCL_WP8.

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S FIFTEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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Response to Staff 15.13 Continued:

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated bonus deprecation tax deduction for 2012 has been modified from the estimate provided in AECC 1.11 c) to a range of $26M - $29M, as shown at APS14831.

c) Please see response to AECC 1.11 (c) for an estimate of the ADIT impacts from all 2011 and 2012 bonus depreciation related to each of the post test year Plant additions on JCL_wp8.

Based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55, the estimated net ADIT impacts from all 2011 and 2012 bonus depreciation has been modified from the estimate provided in AECC 1.11 c) to a range of $79M - $128M, as shown at APS14831.

Additionally, an estimate of the ADIT impacts from all 2011 and 2012 bonus depreciation related to each of the post test year Plant additions has been reflected in the responses to Staff 15.1 and Staff 15.7.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

d) Attached in APS's response to AECC 1.11 (c) at APS14740 are the detailed schedules. Additionally, attached at APS14831 are detailed schedules used to derive the estimated bonus depreciation deduction and related ADIT impacts based upon the updated pro forma calculations for post test year plant provided in APS's Supplemental response to Staff 6.55.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

e) Net ADIT impacts if post test year plant additions were limited to those projected to actually be in service by March 31, 2012 would be materially similar with the information

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Response to Staff 15.13 Continued:

computed at APS14831. Net ADIT for 2012 bonus depreciation for plant additions, limited to either March 31, 2012 or June 30, 2012, would result in zero net ADIT for 2012 bonus depreciation benefits.

As discussed above, without guidance from the IRS that explicitly allows inclusion of these ADIT impacts in rate base, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

Witness: Jason La Benz

ARIZONA PUBLIC SERVICE COMPANY
RESPONSE TO STAFF 15.13

		2011					2012				
Gross Deferred Tax Liability	[A]	$	(141,541)	to	$	(157,605)	$	(4,579)	to	$	(5,087)
Solar Generation Post Test Year Plant Additions		$	(45,976)	to	$	(51,194)	$	(1,531)	to	$	(1,701)
Fossil Generation Post Test Year Plant Additions		$	(10,368)	to	$	(11,545)	$	(39)	to	$	(44)
Nuclear Generation Post Test Year Plant Additions		$	(6,508)	to	$	(7,246)	$	(35)	to	$	(39)
Distribution, G&I Post Test Year Plant Additions		$	(78,689)	to	$	(87,620)	$	(2,973)	to	$	(3,304)
Estimated Deferred Tax Asset - Loss Carryforward	[B]	$	62,848	to	$	29,960	$	15,298	to	$	11,065
Net Deferred Tax Liability	[C] = [A] + [B]	$	(78,693)	to	$	(127,645)	$	-	to	$	-
Solar Generation Post Test Year Plant Additions		$	(25,561)	to	$	(41,462)	$	-	to	$	-
Fossil Generation Post Test Year Plant Additions		$	(5,764)	to	$	(9,350)	$	-	to	$	-
Nuclear Generation Post Test Year Plant Additions		$	(3,618)	to	$	(5,869)	$	-	to	$	-
Distribution, G&I Post Test Year Plant Additions		$	(43,749)	to	$	(70,964)	$	-	to	$	-

	2011	2012	Total			
Tax Basis Eligible for Bonus Depreciation						
Solar Generation Post Test Year Plant Additions	$ 161,176,646	$ 19,443,704	$ 180,620,350			
Fossil Generation Post Test Year Plant Additions	$ 36,347,771	$ 499,297	$ 36,847,069			
Nuclear Generation Post Test Year Plant Additions	$ 22,813,593	$ 440,040	$ 23,253,632			
Distribution Post Test Year Plant Additions	$ 140,150,733	$ 14,060,607	$ 154,211,340			
Smart Grid Post Test Year Plant Additions	$ 26,751,088	$ 4,671,220	$ 31,422,308			
AMI Meters Post Test Year Plant Additions	$ 35,444,273	$ 12,738,031	$ 48,182,304			
IT and Facilities Post Test Year Plant Additions	$ 73,514,385	$ 6,288,106	$ 79,802,491			
Tax Subtotal	$ 496,198,489	$ 58,141,005	$ 554,339,494			
	MINIMUM ESTIMATED BENEFIT			MAX ESTIMATED BENEFIT		
50% Bonus Eligible - Estimate (MAX)	37%	90%		18.50%	100%	
100% Bonus Eligible - Estimate (MAX)	63%	-		81.50%	-	
50% Bonus Depreciation						
Solar Generation	$ (29,817,680)	$ (8,749,667)	$ (38,567,346)	$ (14,908,840)	$ (9,721,852)	$ (24,630,692)
Fossil Generation	$ (6,724,338)	$ (224,684)	$ (6,949,022)	$ (3,362,169)	$ (249,649)	$ (3,611,818)
Nuclear Generation	$ (4,220,515)	$ (198,018)	$ (4,418,532)	$ (2,110,257)	$ (220,020)	$ (2,330,277)
Distribution	$ (25,927,886)	$ (6,327,273)	$ (32,255,159)	$ (12,963,943)	$ (7,030,304)	$ (19,994,246)
Smart Grid	$ (4,948,951)	$ (2,102,049)	$ (7,051,000)	$ (2,474,476)	$ (2,335,610)	$ (4,810,086)
AMI Meters	$ (6,557,190)	$ (5,732,114)	$ (12,289,304)	$ (3,278,595)	$ (6,369,016)	$ (9,647,611)
IT and Facilities	$ (13,600,161)	$ (2,829,648)	$ (16,429,809)	$ (6,800,081)	$ (3,144,053)	$ (9,944,134)
100% Bonus Derprecation						
Solar Generation	$ (101,541,287)	$ -	$ (101,541,287)	$ (131,358,967)	$ -	$ (131,358,967)
Fossil Generation	$ (22,899,096)	$ -	$ (22,899,096)	$ (29,623,434)	$ -	$ (29,623,434)
Nuclear Generation	$ (14,372,563)	$ -	$ (14,372,563)	$ (18,593,078)	$ -	$ (18,593,078)
Distribution	$ (88,294,962)	$ -	$ (88,294,962)	$ (114,222,847)	$ -	$ (114,222,847)
Smart Grid	$ (16,853,185)	$ -	$ (16,853,185)	$ (21,802,137)	$ -	$ (21,802,137)
AMI Meters	$ (22,329,892)	$ -	$ (22,329,892)	$ (28,887,082)	$ -	$ (28,887,082)
IT and Facilities	$ (46,314,063)	$ -	$ (46,314,063)	$ (59,914,224)	$ -	$ (59,914,224)
Estimated Allowable Bonus Depreciation	$ (404,401,768)	$ (26,163,452)	$ (430,565,221)	$ (450,300,129)	$ (29,070,503)	$ (479,370,631)
Estimated Federal Tax Benefit @ 35%	(141,540,619)	(9,157,208)		(157,605,045)	(10,174,676)	
FAS109 Recognition at July 31, 2012	(141,540,619)	(4,578,604)		(157,605,045)	(5,087,338)	

FREEPORT-MCMORAN COPPER & GOLD INC. AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC")
FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION
TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP
A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 8, 2011

AECC 1.11: **Federal Income Tax** - Computation of Increase in Gross Revenue Requirements for the pro forma 12 month test period ending Dec. 31,2010 as shown in Schedule A-1:

a. The Tax Relief, Unemployment Insurance and Job Creation Act of 2010 (signed into law on December 17, 2010) allows greatly accelerated depreciation on qualifying property placed in service in 2011 and 2012 - 100% bonus tax depreciation in 2011 and 50% bonus tax depreciation in 2012. In the August 25, 2010 technical conference, APS stated that its pro forma adjustments summarized in Schedule B-2 and C-2 did not include the impacts of bonus tax depreciation for all qualified property placed in service after Dec 31, 2010 as provided for in the Tax Relief, Unemployment Insurance and Job Creation Act of 2010 (signed into law on December 17, 2010). Please confirm this statement.

b. Assuming APS did not include this bonus depreciation impact, please provide a detailed explanation of why the impact of bonus tax depreciation for all qualified property was not included in the derivation of the APS's Total Company and ACC Jurisdiction pro forma earned rate of returns in this case. If bonus depreciation for qualified property is included for any portion of the period between December 31, 2010 and July 31, 2012, but not the entire period, please identify the period for which bonus depreciation was included.

c. Assuming APS did not include this bonus depreciation impact, please provide all of the adjustments necessary for each APS adjustment, if applicable, shown in Schedule B-2 and C-2 to produce test year pro forma earned results of operations that incorporate all allowed bonus depreciation for qualified property placed in service by July 31, 2012 as authorized by the statutes in effect on Dec 31, 2010, summarized for all of the rate base and expense categories shown in Schedules B-1 and C-1 for both the Total Company and ACC Jurisdiction. These adjustments should allow for a complete assessment of the impact of including bonus tax depreciation in the pro forma earned rates of return. As part of this response, please include all electronic workpapers with formulas intact used to derive the bonus tax depreciation impact.

Witness: Jason La Benz

FREEPORT-MCMORAN COPPER & GOLD INC. AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC")
FIRST SET OF DATA REQUESTS REGARDING THE APPLICATION
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AECC 1.11 Continued;

d. Please prepare a schedule similar to Schedule A-I that identifies the impact on APS's requested revenue increase for the impact of including bonus tax depreciation in APS's pro forma test year data. Please provide this schedule in electronic format with formulas intact.

Response:

a. APS confirms this statement.

b. All bonus depreciation benefits realized by APS as of December 31, 2010 have been included in the Total Company and ACC Jurisdiction pro forma earned rate of returns in this case. Bonus depreciation benefits for future years, which are yet unrealized by the Company, have not been included.

Consistent with the 2007 ACC Settlement, estimated projections of future unrealized deferred taxes related to post-Test Year plant additions (in this instance the period between January 1, 2011 and July 31, 2012) are not reflected in the Total Company and ACC Jurisdiction pro forma earned rate of returns. Inclusions of any such estimated projection of deferred taxes may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers.

c. The total estimated net deferred tax liability related to bonus depreciation for the period January 1, 2011 through July 31, 2012 is between $79 million and $124 million. This estimated net deferred tax liability is based upon a gross deferred tax liability for bonus deprecation between $146 million to $163 million, offset by deferred tax assets for expected federal tax loss carryforwards (created by the inclusion of bonus deprecation in taxable income) of between $41 million to $74 million.

Attached at APS14740 is the detailed calculation of the bonus depreciation impact. Due to uncertainty inherent in the computation of taxable income prior to the end of the year, an adjustment range is provided for the rate base pro forma categories shown on Schedule B-2.

Witness: Jason La Benz

FREEPORT-MCMORAN COPPER & GOLD INC. AND
ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION ("AECC")
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Response to AECC 1.11 Continued:

As discussed in b., above, the Company believes that without an express ruling from the IRS that explicitly allows inclusion of this deferred tax liability, it would be improper to adjust APS's requested revenue increase.

d. Other than the adjustments outline in c., above, which would adjust rate base, APS does not anticipate any other changes to the information presented on Schedule A-1.

As discussed in b., above, the Company believes that without express guidance from the IRS that explicitly allows inclusion of the deferred tax liability, it would be improper to adjust APS's requested revenue increase.

Witness: Jason La Benz

ARIZONA PUBLIC SERVICE COMPANY
RESPONSE TO AECC 1.11 (c)

		2011					2012				
Gross Deferred Tax Liability	[A]	$	(137,979)	to	$	(153,639)	$	(8,298)	to	$	(9,220)
Solar Generation Post Test Year Plant Additions		$	(46,698)	to	$	(51,998)	$	(2,657)	to	$	(2,952)
Fossil Generation Post Test Year Plant Additions		$	(10,849)	to	$	(12,081)	$	(245)	to	$	(272)
Nuclear Generation Post Test Year Plant Additions		$	(6,345)	to	$	(7,065)	$	(362)	to	$	(402)
Distribution, G&I Post Test Year Plant Additions		$	(74,086)	to	$	(82,495)	$	(5,034)	to	$	(5,594)
Estimated Deferred Tax Asset - Loss Carryforward	[B]	$	59,286	to	$	29,960		14,471	to		11,065
Net Deferred Tax Liability	[C] = [A] + [B]	$	(78,693)	to	$	(123,679)	$	-	to	$	-
Solar Generation Post Test Year Plant Additions		$	(26,633)	to	$	(41,858)	$	-	to	$	-
Fossil Generation Post Test Year Plant Additions		$	(6,188)	to	$	(9,725)	$	-	to	$	-
Nuclear Generation Post Test Year Plant Additions		$	(3,619)	to	$	(5,687)	$	-	to	$	-
Distribution, G&I Post Test Year Plant Additions		$	(42,253)	to	$	(66,408)	$	-	to	$	-

	2011	2012	Total			
Tax Basis Eligible for Bonus Depreciation						
Solar Generation Post Test Year Plant Additions	$ 163,708,616	$ 33,735,118	$ 197,443,734			
Fossil Generation Post Test Year Plant Additions	$ 38,034,664	$ 3,114,099	$ 41,148,763			
Nuclear Generation Post Test Year Plant Additions	$ 22,243,815	$ 4,596,347	$ 26,840,162			
Distribution Post Test Year Plant Additions	$ 124,080,367	$ 26,762,468	$ 150,842,835			
Smart Grid Post Test Year Plant Additions	$ 31,028,366	$ 8,501,066	$ 39,529,432			
AMI Meters Post Test Year Plant Additions	$ 32,064,146	$ 13,664,038	$ 45,728,184			
IT and Facilities Post Test Year Plant Additions	$ 72,551,391	$ 14,998,238	$ 87,549,629			
Tax Subtotal	**$ 483,711,365**	**$ 105,371,374**	**$ 589,082,739**			
	MINIMUM ESTIMATED BENEFIT			MAX ESTIMATED BENEFIT		
50% Bonus Eligible - Estimate (MAX)	37%	90%		18.50%	100%	
100% Bonus Eligible - Estimate (MAX)	63%	-		81.50%	-	
50% Bonus Depreciation						
Solar Generation	$ (30,286,094)	$ (15,180,803)	$ (45,466,897)	$ (15,143,047)	$ (16,867,559)	$ (32,010,606)
Fossil Generation	$ (7,036,413)	$ (1,401,345)	$ (8,437,758)	$ (3,518,206)	$ (1,557,050)	$ (5,075,256)
Nuclear Generation	$ (4,115,106)	$ (2,068,356)	$ (6,183,462)	$ (2,057,553)	$ (2,298,174)	$ (4,355,726)
Distribution	$ (22,954,868)	$ (12,043,110)	$ (34,997,978)	$ (11,477,434)	$ (13,381,234)	$ (24,858,668)
Smart Grid	$ (5,740,248)	$ (3,825,480)	$ (9,565,727)	$ (2,870,124)	$ (4,250,533)	$ (7,120,657)
AMI Meters	$ (5,931,867)	$ (6,148,817)	$ (12,080,684)	$ (2,965,934)	$ (6,832,019)	$ (9,797,953)
IT and Facilities	$ (13,422,007)	$ (6,749,207)	$ (20,171,214)	$ (6,711,004)	$ (7,499,119)	$ (14,210,123)
100% Bonus Derprecation						
Solar Generation	$ (103,136,428)	$ -	$ (103,136,428)	$ (133,422,522)	$ -	$ (133,422,522)
Fossil Generation	$ (23,961,838)	$ -	$ (23,961,838)	$ (30,998,251)	$ -	$ (30,998,251)
Nuclear Generation	$ (14,013,603)	$ -	$ (14,013,603)	$ (18,128,709)	$ -	$ (18,128,709)
Distribution	$ (78,170,631)	$ -	$ (78,170,631)	$ (101,125,499)	$ -	$ (101,125,499)
Smart Grid	$ (19,547,870)	$ -	$ (19,547,870)	$ (25,288,118)	$ -	$ (25,288,118)
AMI Meters	$ (20,200,412)	$ -	$ (20,200,412)	$ (26,132,279)	$ -	$ (26,132,279)
IT and Facilities	$ (45,707,376)	$ -	$ (45,707,376)	$ (59,129,383)	$ -	$ (59,129,383)
Estimated Allowable Bonus Depreciation	**$ (394,224,763)**	**$ (47,417,118)**	**$ (441,641,881)**	**$ (438,968,064)**	**$ (52,685,687)**	**$ (491,653,751)**
Estimated Federal Tax Benefit @ 35%	**(137,978,667)**	**(16,595,991)**		**(153,638,822)**	**(18,439,990)**	
FAS109 Recognition at July 31, 2012	**(137,978,667)**	**(8,297,996)**		**(153,638,822)**	**(9,219,995)**	

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.1: ADIT. Please provide ACC jurisdictional amounts for the monthly ADIT items listed on the response to STF 15.7.

Response: Attached as APS14858, which provides the ACC jurisdictional amount corresponding to the Total Company amounts shown on response Staff 15.7.

Witness: Zachary J. Fryer

ARIZONA PUBLIC SERVICE COMPANY
DEFERRED TAXES - ACC JURISDICTIONAL
SUPPORTING SCHEDULE FOR B-1
(dollars in thousands)

	ACCOUNT DESCRIPTION	Actuals Increase (Decrease) RATE BASE 7/31/11	Actuals Increase (Decrease) RATE BASE 8/31/11	Forecast Increase (Decrease) RATE BASE 9/30/11	Forecast Increase (Decrease) RATE BASE 10/31/11	Forecast Increase (Decrease) RATE BASE 11/30/11	Forecast Increase (Decrease) RATE BASE 12/31/11	Forecast Increase (Decrease) RATE BASE 1/31/12	Forecast Increase (Decrease) RATE BASE 2/29/12	Forecast Increase (Decrease) RATE BASE 3/31/12
1.	Total Deferred Taxes per General Ledger	$ (1,519,663)	$ (1,576,602)	$ (1,577,653)	$ (1,581,501)	$ (1,580,248)	$ (1,581,978)	$ (1,583,556)	$ (1,580,034)	$ (1,572,089)
	Exclude:									
2.	Reg Asset-Power Supply Adjustor Mark to Market	(24,323)	(24,323)	(17,971)	(17,427)	(17,604)	(17,360)	(17,288)	(17,447)	(17,878)
3.	Reg Asset-Transmission Vegetation Management	-	-	-	-	-	-	-	-	-
4.	Reg Asset-Unamortized Loss on Reaquired Debt	(8,062)	(7,909)	(7,844)	(7,822)	(7,829)	(7,819)	(7,814)	(7,825)	(7,854)
5.	Option II Benefits (Includes Reg Asset and Def Comp)	3,970	3,604	3,449	3,395	3,413	3,388	3,383	3,395	3,428
6.	Reg Asset-Demand Side Management	(4,203)	(2,711)	(2,078)	(1,857)	(1,929)	(1,830)	(1,812)	(1,851)	(1,956)
7.	Reg Liab-Renewable Energy Standard	19,521	20,338	20,684	20,805	20,766	20,820	20,846	20,788	20,633
8.	Reg Liab-Power Supply Adjustor	8,908	1,015	(2,333)	(3,501)	(3,120)	(3,645)	(3,613)	(3,685)	(3,878)
9.	Renewable Energy Incentives	46,383	52,157	54,606	55,460	55,182	55,566	55,679	55,427	54,744
10.	Mark to Market	73,088	62,905	80,444	79,887	80,069	79,818	79,744	79,910	80,360
11.	OCI-Pension Taxes	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559	20,559
12.	Superfund	1,634	1,590	1,571	1,565	1,567	1,564	1,563	1,566	1,574
13.	Other	966	966	966	966	966	966	966	966	966
14.	Subtotal Of Exclusions	138,441	128,191	152,053	152,030	152,040	152,027	152,213	151,803	150,698
15.	Total Deferred Taxes (Line 1 - Line 14)	$ (1,658,104)	$ (1,704,793)	$ (1,729,706)	$ (1,733,531)	$ (1,732,288)	$ (1,734,005)	$ (1,735,769)	$ (1,731,837)	$ (1,722,787)

ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 1, 2011

Staff 9.2: How much cost has APS included in rate base and operating expenses related to the project for the Integrated Energy System with Beneficial CO2 Reuse? If any amounts have been included, provide the following information:

a. Identify and provide the work order related to the project.

b. List all rate base and operating expense amounts by account.

c. List all project costs by vendor amount.

d. List all reimbursements from the U.S. Department of Energy (DOE) under Award No. DE-FE0001099.

e. List the amount of reserve or liability against DOE provided funds recorded through December 31, 2010.

f. List all accounting entries related to this project through the present.

Response: The Company Test Year cost of service does not include costs in rate base associated with the Integrated Energy System (IES) project or the Substitute Natural Gas (SNG) project referenced in Staff 9.3. The amount of operating expense recorded to these projects in 2010 were as follows:

IES project expenses	$2,334,478 (see APS14734)
SNG project expenses	502,924 (see APS14735)
Legal/Audit expenses	291,522 (see Staff 9.4)
Proforma Adjustment	(1,000,000)
Total	$2,128,924

The above noted proforma adjustment is discussed in the testimony of Jason La Benz and is reflected on Schedule C-2, column 27, Page 9 of 12 of the Company's filing. The associated workpaper is JCL_39 page 2 of 3 ("remove grant reserve"). This adjustment removed project costs incurred prior to 2010 that were recorded as expense in the Test Year.

The remaining expenses ($2,128,924) were included in the Test Year within above-the-line research and development accounts. However, given on-going discussions with the Department of Energy regarding these projects, APS will remove the expenses recorded during the Test Year that are associated with these projects.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S NINTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
SEPTEMBER 1, 2011

Staff 9.3: How much cost has APS included in rate base and operating expenses related to the project for the Development of a Hydrogasification Process for the Co-Production of Substitute Natural Gas (SNG) and Electric Power from Western Coals?

a. Identify and provide the work order related to the project.

b. List all rate base and operating expense amounts by account.

c. List all project costs by vendor amount.

d. List all reimbursements from the U.S. Department of Energy (DOE) under Award No. DE-FC26-06NT42759.

e. List the amount of reserve or liability against DOE provided funds recorded through December 31, 2010.

f. List all accounting entries related to this project through the present.

Response: Please see APS's response to Staff 9.2.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.2: Grant funded projects.

Refer to the response to STF 15.23, APS14811, page 5 of 18. Please show, by account, how APS accounted for the project expenditures and the related government reimbursements in 2010 for each of the following projects:

a. High Penetration of Photovoltaic Generation Study (HPS).

b. Distributed Energy Leadership Program (DELP).

c. Membrane Technology Research (MTR)

Response: Please see the table below for the requested information:

Grant Name	Account	2010	Reimbursement
a) HPS	1430	$ 319,904.74	See STF 19.21
	5880	$(15,303.76)[1]	
b) DELP	1430	$ 17,824.32	See STF 19.21
	5880	$ 5,962.39	
c) MTR	1430	$ (14,978.95)	$ 326,588.54
	4560		$ 76,601.99
	5140	$ 109.53	
	9302	$ 9,667.46	

Please see APS's response to Staff 19.21 for the government reimbursements for HPS and DELP.

1. Project costs for the HPS award are recorded to FERC 1430. As part of the monthly accounting cycle, APS's portion of the costs or "cost share" is moved from FERC 1430 to FERC 5880 through a system allocation. This allocation inadvertently moved $53,727.14 of DOE reimbursements to FERC 5880 causing a credit in FERC 5880. In July 2011, a reconciling entry was made to correct FERC 1430 and FERC 5880.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTIETH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 20.3: Post test year plant for grant funded projects.

Has APS included costs for any grant-funded projects in its request for post test year plant? If not, explain fully why not. If so:

a. Please show the amounts of actual plant additions for grant-funded plant by month, by account, through the most current date for which actual information is available and the Company's best estimates for months after that through March 31, 2012.

b. Please show by account, by month, the related grant funding for each such project.

Response: (a)-(b) No. APS has not included costs for any grant-funded projects in its request for plant additions or post-Test Tear plant.

Witness: Jeff Guldner

**ARIZONA PUBLIC SERVICE COMPANY
PRE-FILED SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-XXXX
JUNE 1, 2011**

Pre-filed 1.40: Advertising Expense. For each of the advertising expense amounts in the Test Year, please provide an itemization of the amount by advertising campaign/advertisement.

Response: Attached, in Excel, as APS14082 is a summary of Test Year advertising expenses charged to FERC account 930.1 "General Advertising Expenses."

Witness: Jay La Benz

Advertsing Expense

ITEM/DESCRIPTION		TOTAL AMOUNT
Communications Payroll Expense	$	131,623
Breakfast at the Zoo		40,688
Miscellaneous Admin expense		3,238
SUBTOTAL:	$	**175,550**
Energy Conservation/Sustainability		
Sustainability TV Campaign Prod./Talent	$	1,594,012
KNXV-TV		522,851
External Advertising retainer		480,000
Hispanic DSM Rebates		195,923
Green Up Arizona		143,523
General APS advertising		128,106
Sustainability Hispanic TV Advertising		113,975
Energy Star homes expense		33,979
Latino Perspectives Magazine Advertising		33,700
COX Gross Advertising		25,500
Clear Channel Outdoor Refrig recycling		25,000
APS Home Energy expense		22,060
Luke AFB Supplement		11,542
Raising Arizona Kids Refrig recycling		10,927
Latino Future Refrig recycling		7,035
Energy Daily Advertising		6,470
Flagstaff Community Power expense		5,864
Green Choice expense		5,354
Solar Today advertising		4,495
Clear Channel Outdoor bulletins		1,370
Sustaining AZ Production		1,200
Renewables advertising		313
SUBTOTAL:	$	**3,373,201**
TOTAL	$	**3,548,750**

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.1: General Advertising Expense. Refer to the response to Prefiled 1.40, APS14082. Provide copies of the advertisements related to the following items:

a) Sustainability TV Campaign Prod/Talent - $1.594 million

b) KNVX-TV, $522,851

c) External Advertising Retainer, $480,000

d) Green Up Arizona, $143,523

e) General APS Advertising, $128,106

f) Sustainability Hispanic TV Advertising, $113,975

g) Latino Perspectives Magazine Advertising, $33,700

h) COX Gross Advertising, $25,500

i) Clear Channel Outdoor Refrig recycling, $25,000

j) APS Home Energy Expense, $22,060

k) Luke AFB Supplement, $11,542

l) Raising Arizona Kids Refrig Recycling, $10,927

m) Energy Daily Advertising, $6,470

n) Flagstaff Community Power expense, $5,864

o) Clear Channel Outdoor bulletins, $1,370

p) Breakfast at the Zoo, $40,688

Response:

(a) Please see APS19000, attached.

(b) Please see APS19001, attached.

(c) The external advertising retainer PO can be found in response to Staff 21.2. Their services include general account management for advertising production.

(d) Please see APS19002, attached.

(e) The general advertising amount of $128,006 does not have a specific advertisement to provide, rather this supports multiple ads already contained in this response.

(f) Please see APS19003, attached.

(g) Please see APS19004, attached.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Response to Staff 21.1 Continued:

(h) Please see APS19005, attached.

(i) Please see APS19006, attached.

(j) Please see APS19007, attached.

(k) Please see APS19008, attached.

(l) Please see APS19009, attached.

(m) Please see APS19010, attached.

(n) Please see APS19011, attached.

(o) Please see APS19012, attached.

(p) The Breakfast at the Zoo charges did not encompass advertising and should have been recorded to Account 930.2, instead of 930.1. No advertising copy is available.

Witness: Jeff Guldner

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.3: Please provide an update of the Trial Balance (APS14766, 7 pages) for fiscal 2011 through period 9 (September 2011).

Response: The Company is in the process of closing its books for the required SEC quarterly filing. Once the Company has filed its Form 10-Q, it will provide the Trial Balance for fiscal 2011 through period 9 (September 2011).

Supplemental Response: Please see APS14965 for the requested trial balance.

Witness: Jay La Benz

APS® Report ID: PWGLC006 | BU: APSCO | Fiscal Year: 2011 | To Period: 9

Trial Balance by Account w/ Beginning Balance

Page 1
Run Date: 11/1/2011
Run 11:07:37 AM

Account	Description		Beginning Balance	Year To Date	End Balance
Balance Sheet Accounts					
5880000	Dist-Misc Distribution Exp Ops	$0.00	$24,545,211.32	$24,545,211.32	
5890000	Dist-Rents Ops	$0.00	$408,118.02	$408,118.02	
5900000	Dist-Supv and Engnrg Maint	$0.00	$891,333.92	$891,333.92	
5910000	Dist-Maint of Structures	$0.00	$497,653.55	$497,653.55	
5920000	Dist-Maint of Station Equip	$0.00	$1,350,449.06	$1,350,449.06	
5930000	Dist-Maint of OH Lines	$0.00	$10,420,990.11	$10,420,990.11	
5940000	Dist-Maint of UG Lines	$0.00	$6,193,194.81	$6,193,194.81	
5950000	Dist-Maint Line Transformers	$0.00	$2,429,262.78	$2,429,262.78	
5960000	Dist-Maint-StrtLghtg & Signal	$0.00	$287,198.50	$287,198.50	
5970000	Dist-Maint of Meters	$0.00	$(1,811.23)	$(1,811.23)	
5980000	Dist-Maint of Misc Distrib Plt	$0.00	$3,019,015.76	$3,019,015.76	
5990090	Income Summary IU	$0.00	$321,962,201.12	$321,962,201.12	
9010000	Supervision	$0.00	$2,000,384.71	$2,000,384.71	
9020000	Meter Reading	$0.00	$7,090,446.95	$7,090,446.95	
9030000	Cust Records and Collection	$0.00	$28,362,719.69	$28,362,719.69	
9040000	Uncollectible Accts	$0.00	$4,806,169.01	$4,806,169.01	
9050000	Misc Cust Accts	$0.00	$406,569.68	$406,569.68	
9070000	Supervision-Cust Service	$0.00	$1,253,388.47	$1,253,388.47	
9080000	Customer Assistance	$0.00	$53,706,828.80	$53,706,828.80	
9090000	Info-Instructional Advertising	$0.00	$406,277.06	$406,277.06	
9100000	Misc Cust Serv and Info	$0.00	$1,047,346.76	$1,047,346.76	
9120000	Demonstrating and Selling	$0.00	$2,543,155.55	$2,543,155.55	
9130000	Advertising-Sales Expenses	$0.00	$140,612.23	$140,612.23	
9160000	Misc Sales Expenses	$0.00	$3,457,789.89	$3,457,789.89	
9200000	A&G Payroll - Operations	$0.00	$60,012,774.90	$60,012,774.90	
9200003	Supply Chain AG	$0.00	$1,735,914.57	$1,735,914.57	
9210000	Office Supplies & Expenses	$0.00	$13,979,014.61	$13,979,014.61	
9220000	Admin Exp Transferred-Credit	$0.00	$(18,886,856.64)	$(18,886,856.64)	
9230000	Outside Services Employed	$0.00	$9,671,083.45	$9,671,083.45	
9240000	Property Insurance	$0.00	$4,872,394.88	$4,872,394.88	
9250000	Injuries and Damages	$0.00	$4,127,660.66	$4,127,660.66	
9250001	Injuries and Damages-Benefits	$0.00	$959,189.15	$959,189.15	
9250011	BTL Injuries and Damages	$0.00	$12,977.30	$12,977.30	
9260000	Employee Pensions&Benefit	$0.00	$1,309,788.57	$1,309,788.57	
9260001	Emp Pensions&Benefit-Benefits	$0.00	$62,784,312.01	$62,784,312.01	
9280000	Regulatory Commission	$0.00	$14,071,174.05	$14,071,174.05	
9301000	General Advertising Expenses	$0.00	$1,800,728.47	$1,800,728.47	
9302000	Misc General Expenses	$0.00	$(35,528,769.16)	$(35,528,769.16)	
9310000	Rents - O&M	$0.00	$5,655,456.42	$5,655,456.42	
9350000	Maintence of General Plant	$0.00	$3,873,720.64	$3,873,720.64	
Subtotal for Income Statement Accounts		$0.00	($0.00)	$(0.00)	
Grand Total :		$0.00	$(0.00)	$(0.00)	

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.4: General Advertising Expense. Why is the 2010 General Advertising Expense (Account 9301000) of $3,548,750 (APS14082 and APS14165, page 9) so much higher than the 2009 amount of $1,807,823 (APS14164, page 8)? Identify, quantify and explain the new and/or expanded advertising programs.

Response: The 2010 general advertising expense was greater than 2009 due to expanded energy efficiency campaigns. These campaigns help APS achieve the Energy Efficiency goals established by the ACC which require APS to reduce sales by 22% by 2020.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.5: General Advertising Expense.

a) What was the General Advertising Expense amount recorded for Account 9301000 for 2008?

b) What is the budgeted General Advertising Expense for 2011?

Response:

(a) In 2008 the amount recorded in Account 930.1 was $3,435,898.

(b) The budget for 2011 is $ 2,059,000 and for 2012 is $4,060,000.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.10: General Advertising Expense. Refer to the response to Pre-filed 1.40, APS14082, and to the responses to STF 21.1 through 21.5.

a) What was the purpose of, and ratepayer benefit resulting from, the $40,688 Breakfast at the Zoo expense?

b) Provide the invoices and support for the $40,688 Breakfast at the Zoo expense.

c) Was the Breakfast at the Zoo for APS employees? If not, who was it for?

d) Provide the invoices for the $480,000 External Advertising Retainer.

e) Provide the invoices for 2010 work that were submitted per paragraph 8.2 of the contract that was provided in response to STF 21.2.

f) Please reconcile the invoices provided in response to part c with the $480,000 amount for External Advertising Retainer.

g) Where specifically in the contract that was provided in response to STF 21.2 is a retainer specified?

h) Why is the General Advertising Expense budget for 2011 of $2.059 million per the response to STF 21.5 so much lower than the $3.549 million amount for 2010 per APS14082/response to Pre-filed 1.40.

i) Provide a comparison of the 2011 budget with the actual expense recorded in Account 930.1, General Advertising Expense, for year-to-date 2011. Include explanations of budget variances.

Response:

a) The event was attended by approximately 2,000 employees and their families. The general purpose of the event was to partner with the Phoenix Zoo in Corporate wide recognition and appreciation of employee efforts to serve APS's over 1 million customers.

b) Attached as APS14975 is the requested invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective agreement.

c) Yes, it was for an employee event.

d) Please see APS14952 through APS14963, attached, for the invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective

ARIZONA CORPORATION COMMISSION
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OCTOBER 27, 2011

Response to Staff 27.10 Continued:

agreement.

e) Attached as APS14979 are the Test Year invoices. Please note these invoices are confidential and are being provided pursuant to an executed protective agreement.

f) No reconciliation is necessary, the amounts tie.

g) The retainer was not specified in the contract. Rather, the retainer was an amount agreed upon to establish a baseline fund for advertising and account management support for the necessary advertising workload.

h) In 2010, the General Advertising Expense budget included $1.6 million dollars to fund production costs for a new Sustainability TV and radio campaign and these ads continued to run in 2011.

i) Please see APS14964, attached, for the budget to actual comparison.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY SECOND SET OF DATA REQUESTS
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Staff 32.1: Payroll Expense/Payroll Annualization.

a. Explain fully and in detail how and why the as-recorded 2010 test year payroll amounts changed from APS' original filing, JCL_WP23, page 2 of 10 to APS14945, page 2 of 10, as shown in the following table:

Component	APS Original Filing JCL_WP23 Page 2 of 10 Test Year	APS Oct 25, 2011, Update APS14945 Page 2 of 10 Test Year	Test Year Difference
Base Payroll	$ 553,891,955	$ 548,692,451	$ (5,199,504)
Unemployment	$ 3,107,699	$ 3,107,453	$ (246)
Social Security Tax	$ 32,996,495	$ 32,725,341	$ (271,154)
Medicare Tax	$ 8,031,433	$ 7,956,041	$ (75,393)
Total	$ 598,027,583	$ 592,481,286	$ (5,546,297)

b. Identify all amounts in the "Test Year" column on APS14945, page 2 of 10 that do not represent actual recorded test year amounts.

c. Identify all amounts in the "Test Year" column on JCL_WP23, page 3 of 10 that do not represent actual recorded test year amounts.

d. Identify when APS first discovered an error in its "Test Year" amounts on JCL_WP23, page 2 of 10, and explain in detail the nature of the error.

e. Explain fully and in detail exactly what was not known and certain about the "Wage Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10.

f. Explain fully and in detail exactly what was not known and certain about the "Employee Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10.

g. Why have the "Wage Change to March 2011" amounts and the "Employee Change to March 2011" amounts reflected in APS' original filing on JCL_WP23, page 2 of 10 change in APS' October 26, 2011 update per APS14945, page 2 of 10; explain fully and show and explain in detail exactly why such March 2011 amounts should have changed and did change:

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S THIRTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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Staff 32.1 Continued:

Component	APS Original Filing JCL_WP23 Page 2 of 10 Total	APS Original Filing JCL_WP23 Page 2 of 10 APS O&M	APS Oct 25, 2011, Update APS14945 Page 2 of 10 Total	APS Oct 25, 2011, Update APS14945 Page 2 of 10 APS O&M	Difference Total	Difference APS O&M
Wage Change to March 2011	$ 20,784,713	$ 10,172,941	$ 23,119,516	$ 11,315,694	$ 2,334,803	$ 1,142,753
Employee Change to March 2011	$ (23,446,008)	$ (11,475,494)	$ (19,286,438)	$ (9,439,620)	$ 4,159,570	$ 2,035,874

Response:

a) The selling of paid time off and paid earned & accrued vacation was mistakenly included as base pay in the original calculation of Test Year base pay; therefore, the actual Test Year total base payroll, unemployment, Social Security and Medicare were overstated by $5,546,297. Therefore, when computing the pro forma, the necessary adjustment was correspondingly understated.

b) All amounts in the "Test Year" column on APS14945, page 2 of 10, represent actual recorded Test Year amounts.

c) The amounts in the "Test Year" column on APS14945, page 3 of 10, represent actual recorded Test Year amounts and should be used to replace those originally filed as JCL_WP23 page 3 of 10.

d) The error was found when updating the Payroll Annualization Pro Forma to reflect the new Union wage contract for the October 25, 2011 Update. See Staff 32.1 (a) for the explanation of the error.

e) At the time the Payroll Annualization Pro Forma was developed March 2011 actual employee wages were known and were used in the pro forma adjustment.

f) At the time the Payroll Annualization Pro Forma was developed March 2011 actual employee head counts wages were known and were used in the pro forma adjustment.

g) The changes to both the Wage Change and Employee Change from the original filing on JCL_WP23, page 2 of 10 to the APS's October 26, 2011 update APS14945, page 2 of 10 are all related to the correction to test year base payroll as explained in Staff 32.1 (a).

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWELFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
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E-01345A-08-0172
OCTOBER 9, 2008

Staff 12.27 Meters. Refer to the Company's response to Staff 6.43e, Staff 6.15 and APS12960. (a) Please confirm that on APS12960 a "vintage" and an "activity year" of 2007 would indicate a transaction occurring in 2007. If not, explain fully why not. (b) Also, explain what the "vintage" and "activity year" mean in APS12960 if anything different than the definitions listed in APS12959. (c) Please confirm that "adjusting year code" of "10" on APS12960 indicates a normal addition and "20" indicates a normal retirement. If not, explain fully why not. (d) Please confirm that in 2007 APS added $12,186,852 as a normal addition in Account 37001 and in 2005 added $11,535,469. If this is not the case, explain fully why not. (e) Please show in detail the amounts that APS added to plant in Account 37001 in each year 2005, 2006 and 2007 for normal additions. (f) Please confirm that in 2006 APS added $591,859 in Account 37002 as a normal addition. If this is not the case, explain fully why not and show in detail the amounts that APS added to plant in Account 37002 in 2006 for normal additions. (g) Please provide all work orders and cost-benefit analysis APS has for making normal additions of plant into Accounts 37001 and 37002 in each year 2005, 2006, 2007 and 2008. (h) Does APS project making any normal additions (Code 10 per APS12959) of plant into either account, 37001 or 37002, in 2008, 2009 or 2010? If not, explain fully why not. If so, please show the Code 10 "normal" additions to each of these accounts projected for each year.

Response:

(a) Yes. Please see response (d).

(b) APS's transaction definition is the same as in APS12959 on page 2.

(c) Transaction code 10 is a normal addition and transaction code 20 is a normal retirement.

(d) The 37001 additions of $12,186,852 and $11,535,469 for 2007 and 2005 respectively are NOT the total additions for the specified vintages. The total additions for 2007 were $11,935,595 and for 2005 were 11,953,122. See schedule attached hereto at APS08997.

ARIZONA CORPORATION COMMISSION
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OCTOBER 9, 2008

Staff 12.27

Response Continued:

(e) Attached as APS08997 is the requested schedule.

(f) Yes, however the 2006 addition was transferred in 2008 to 37001.

(g) The work orders used for capitalizing meter in utility accounts 37001 and 37002 are 63-1000, 63-2000 and 63-1020. In response to the cost-benefit analysis question, please see Staff Interim 2.10.

(h) The estimated meter additions for 37001 are $12.5M in 2008, $8.9M in 2009 and $4.2M in 2010. For utility account 37002, APS does not plan on any additions. 37002 are the older meter types that will no longer be purchased. APS is expecting a full AMI rollout.

Supplemental Response:

(g) The work orders used for capitalizing meter in utility accounts 37001 and 37002 are 63-1000, 63-2000 and 63-1020. These charge numbers were established in the late 90's. They are fixed in our inventory system in order to facilitate the pre-capitalization process. The approval for meter purchases is done at the Purchase Order (PO) level. The projected installs are measured with what is in stock in order to determine what needs to be purchased.

In response to the cost-benefit analysis question, please see Staff Interim 2.10.

Witness: Jason La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S SEVENTEENTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
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E-01345A-08-0172
OCTOBER 24, 2008

Staff 17.7 Depreciation. Account 370.01. Refer to APS09011, 2008 Depreciation Study workpapers. (a) Show in detail how each of the "derived additions" in column c on page 194 of 374 was derived. Include complete supporting calculations. (b) Provide the accounting entries and all journal entry support for the $65,427,927 "sales, transfer and adjustment" amount for 2004 in column E on page 195 and page 196. (c) On page 194, please explain what the amounts in column E, "amount surviving" based on experience to 12/31/2007 represent. (d) Are the "amounts surviving" for 1998 through 2003 plant in account 370.01 as of 12/31/2007 consistent with a five-year amortization? If not, explain fully why not. If so, explain in detail how. (e) What depreciation or amortization rate did APS use for Account 370.01 in each year, 1998 through 2007?

Response:

(a) All transactions used to derive Column C were provided in response to Staff 6.15. Open the database, filter on the desired account, filter all transactions excluding Code 20s and sum the resulting transactions for each vintage year to produce results shown in the schedule attached as APS13179.

(b) The $65,427,927 was a system transfer for meters. APS had one depreciation group for meters excluding AMI meters. In 2004 these meters were split into two distinct depreciation groups, electronic meters and the electromechanical meters. 37001 are the newer electronic meters and 37002 are the old electromechanical meters. The $65.4M was the transfer from the 37002 depreciation group to 37001.

Please see APS09011 pages 195, 202 and 203. Page 202 and 203 show the transfer from (credit) 37002 (electromechanical meters) to 37001 electronic meters which is shown as a debit on page 195.

(c) Column C is the age distribution of surviving plant at December 31, 2007 as also reported in the Generation Arrangement shown in Column C, page 193. An age distribution is plant surviving (*i.e.*, in service) by vintage year of placement.

ARIZONA CORPORATION COMMISSION
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ARIZONA PUBLIC SERVICE COMPANY,
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OCTOBER 24, 2008

Staff 17.7

Response Continued:

(d) Yes. These vintages will be retired upon implementation of amortization accounting. Vintages 2003–2007 and any subsequent additions will be retired as each vintage achieves an age equal to the amortization period. Amortization over five years is consistent with APS's commitment to a program of replacing electronic and electromechanical meters with AMI meters by 2012. See also White direct testimony, page 12, lines 1 ff.; White Attachment REW–1, page 3–4; response to Staff 6.43; response to Staff 6.51; response to Staff 12.25; and response to Staff 12.27.

(e) The depreciation rates from 1998 to 2007 were as follows:

<u>37001: Electronic Meters</u>	
1998 to March 2005:	4.54%
April 2005 to June 2007:	3.61%
July 2007 to present:	3.68%

<u>37002: Electromechanical Meters</u>	
1998 to March 2005:	4.54%
April 2005 to June 2007:	2.84%
July 2007 to present:	3.02%

Witness: Ronald White

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON - CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.)	DOCKET NO. E-01933A-05-0650
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.)	DOCKET NO. E-01933A-07-____

Direct Testimony of

Dr. Kimbugwe A. Kateregga

on Behalf of

Tucson Electric Power Company

July 2, 2007

Exhibit KAK–1

2007 Depreciation Rate Study

Tucson Electric Power Company

–Local Generation
–Non–Local Generation
–Distribution and General

Prepared by
Foster Associates, Inc.

TUCSON ELECTRIC POWER COMPANY Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed				
Account Description	Rem. Life	Fut. Net Salvage	Accrual Rate	Avg. Life	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H	I
DISTRIBUTION PLANT								
360.00 Rights-of-Way			2.22%		43.78		37.61%	1.43%
361.00 Structures and Improvements		-10.0%	2.44%		44.83		26.99%	1.63%
362.00 Station Equipment		-19.0%	4.25%		46.02		33.01%	1.46%
364.00 Poles, Towers and Fixtures		-59.0%	5.48%		39.16		35.98%	1.63%
365.00 Overhead Conductors and Devices		-17.0%	3.66%		41.83		38.71%	1.47%
366.00 Underground Conduit		-40.0%	2.33%		43.44		38.11%	1.42%
367.00 Underground Conductors and Devices		33.0%	1.63%		32.32		38.89%	1.89%
368.OH Line Transformers - Overhead		-15.0%	3.38%		26.12		51.83%	1.84%
368.UG Line Transformers - Underground		-15.0%	3.38%		23.28		41.39%	2.52%
369.OH Services - Overhead		-34.0%	3.83%		28.70		53.55%	1.62%
369.UG Services - Underground		-34.0%	3.83%		47.81		28.30%	1.50%
370.00 Meters		-25.0%	3.79%		19.73		40.91%	2.99%
373.00 Street Lighting and Signal Systems		-25.0%	4.46%		36.67		36.24%	1.74%
374.00 Asset Retirement Costs		-7.0%	3.22%		31.53		6.20%	2.97%
Total Distribution Plant			3.35%		33.61		38.52%	1.82%
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements			2.22%		21.45		54.04%	2.14%
391.CM Office Furn. and Equip. - Computer			20.00%		2.95		57.04%	14.56%
392.C0 Transportation Equipment - Class 0		16.0%	8.87%		14.63	15.0%	25.99%	4.03%
392.C1 Transportation Equipment - Class 1		16.0%	14.00%		5.10	15.0%	41.06%	8.62%
392.C2 Transportation Equipment - Class 2		21.0%	11.29%		4.99	25.0%	36.55%	7.71%
392.C3 Transportation Equipment - Class 3		18.0%	10.25%		7.07	15.0%	41.05%	6.22%
392.C4 Transportation Equipment - Class 4		9.0%	7.00%		9.80	10.0%	43.96%	4.70%
392.C5 Transportation Equipment - Class 5		1.0%	7.07%		10.67	5.0%	38.28%	5.32%
396.00 Power Operated Equipment			3.33%		11.46	5.0%	46.95%	4.19%
397.00 Communication Equipment			6.67%		18.13		32.72%	3.71%
Total Depreciable			7.57%		9.53	4.0%	44.54%	5.31%
Amortizable								
391.FE Office Furn. and Equip. - Furniture	← 24 Year Amortization →				← 24 Year Amortization →			
393.00 Stores Equipment	← 15 Year Amortization →				← 15 Year Amortization →			
394.00 Tools, Shop and Garage Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
395.00 Laboratory Equipment	← 17 Year Amortization →				← 17 Year Amortization →			
398.00 Miscellaneous Equipment	← 20 Year Amortization →				← 20 Year Amortization →			
Total Amortizable			8.00%		11.16		43.56%	5.06%
Total General Plant			7.65%		9.75	3.3%	44.37%	5.26%
TOTAL INVESTMENT			3.96%		25.53	0.5%	39.34%	2.30%
NET SALVAGE								
108.02 *Distribution*	*43.08*	*-50.0%*			*33.61*	*-15.0%*	*5.68%*	*0.28%*
Total Net Salvage					33.61		5.68%	0.28%
TOTAL UTILITY			3.96%		25.53	-6.7%	44.22%	2.54%

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQUEST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. G-04204A-06-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Gas, Inc.

December 15, 2006

Exhibit REW–2

2006 Depreciation Rate Review

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

UNS ELECTRIC, INC. Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	38.00		2.92%	30.16		5.64%	3.13%
Total Depreciable			2.92%	30.16		5.64%	3.13%
Amortizable							
302.00 Franchises and Consents	38.00			← 25 Year Amortization →			
303.00 Miscellaneous Intangible Plant	38.20			← 15 Year Amortization →			
303.WC Misc. Intangible - WAPA Fiber Optic	38.20		4.13%	← 23 Year Amortization →			
303.PC Misc.Intangible Plant - PC Software	31.00		20.00%	← 5 Year Amortization →			
Total Amortizable			4.23%	7.21		61.05%	3.06%
Total Intangible Plant			3.79%	10.88		42.48%	3.09%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	38.00		1.38%	29.50		39.01%	2.07%
342.00 Fuel Holders, Producers and Accessories	38.20		2.42%	32.63		18.06%	2.51%
343.00 Prime Movers	37.00		2.34%	26.17		33.89%	2.53%
344.00 Generators	22.60		0.67%	36.15		15.62%	2.33%
345.00 Accessory Electric Equipment	39.50		2.20%	29.39		31.02%	2.35%
346.00 Miscellaneous Power Plant Equipment	31.00		1.87%	33.34		12.02%	2.64%
Total Other Production Plant			2.00%	28.73		29.41%	2.46%
TRANSMISSION PLANT							
350.RW Rights of Way				31.35		36.56%	2.02%
352.00 Structures and Improvements	19.70		3.77%	12.75		60.15%	3.13%
353.00 Station Equipment	23.00		2.92%	21.72		31.49%	3.15%
354.00 Towers and Fixtures	12.40		4.08%	15.92		20.00%	5.03%
355.00 Poles and Fixtures	15.90	-10.0%	5.77%	12.68	-10.0%	53.19%	4.48%
356.00 Overhead Conductors and Devices	30.10		2.71%	23.85		36.50%	2.66%
359.00 Roads and Trails	44.90		2.01%	35.18		29.05%	2.02%
Total Transmission Plant			3.68%	18.90	-2.9%	39.12%	3.41%
DISTRIBUTION PLANT							
360.RW Rights of Way				27.71		43.70%	2.03%
361.00 Structures and Improvements	23.60		3.20%	25.54		24.39%	2.96%
362.00 Station Equipment	15.30		4.82%	11.54		52.77%	4.09%
364.00 Poles, Towers and Fixtures	18.90	-10.0%	4.23%	14.83	-10.0%	48.65%	4.14%
365.00 Overhead Conductors and Devices	18.40	-10.0%	4.36%	15.16	-10.0%	47.39%	4.13%
366.00 Underground Conduit	21.50		4.28%	18.66	-5.0%	34.33%	3.79%
367.00 Underground Conductors and Devices	14.30		5.36%	14.20		37.50%	4.40%
368.00 Line Transformers	14.20	-5.0%	4.93%	13.46	-5.0%	42.69%	4.63%
369.OH Services - Overhead	18.30		4.23%	14.43		45.63%	3.77%
369.UG Services - Underground	18.30		4.23%	16.26		38.99%	3.75%
370.00 Meters	26.20	-5.0%	3.25%	24.14	-5.0%	29.99%	3.11%
373.00 Street Lighting and Signal Systems	17.40		4.55%	16.64		32.78%	4.04%
Total Distribution Plant			4.50%	14.75	-6.0%	44.74%	4.16%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	27.80		2.89%	29.03		23.14%	2.65%
392.C1 Transportation Equipment - Class 1			25.00%	4.00		49.01%	12.75%
392.C2 Transportation Equipment - Class 2			25.00%	3.02		48.68%	16.99%
392.C3 Transportation Equipment - Class 3			25.00%	3.28		33.72%	20.21%
392.C4 Transportation Equipment - Class 4			12.50%	1.63		78.05%	13.47%
392.C5 Transportation Equipment - Class 5			12.50%	6.58		17.40%	12.55%
396.00 Power Operated Equipment	6.80		3.33%	5.16		64.30%	6.92%
Total Depreciable			12.12%	4.13		54.16%	11.33%

DIRECT TESTIMONY
OF
DR. RONALD E. WHITE

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

June 2008

2008 Depreciation Rate Study

Arizona Public Service Company

Prepared by
Foster Associates, Inc.

tion period. Reserve imbalances created by the recommended amortization periods were eliminated by a systematic redistribution of recorded reserves. Reserve imbalances for the proposed amortization accounts were distributed to the remaining depreciable accounts in the General plant function. Net salvage realized in the future will be netted against current–year vintage additions.

Amortization accounting is also recommended for Account 370.01 (Meters – Electronic) and Account 370.02 (Meters – Electromechanical). APS has committed to a program of replacing electronic and electromechanical meters with AMI (Advanced Metering Infrastructure) meters by 2012. Accordingly, a 5–year amortization period is recommended for Accounts 370.01 and 370.02. The current projection life of 26 years for electronic meters is recommended for AMI meters pending sufficient retirement experience to estimate service lives for AMI metering technology. Reserve imbalances associated with the proposed meter amortization accounts were distributed to the remaining depreciable accounts in the Distribution plant function.

PROPOSED DEPRECIATION RATES

Table 2 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended in the 2008 study for APS.

Function	Accrual Rate			2008 Annualized Accrual		
	Present	Proposed	Diff.	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.86%	3.51%	-0.35%	$57,991,639	$52,743,069	($5,248,570)
Nuclear Production	2.80%	2.78%	-0.02%	68,608,141	68,160,962	(447,179)
Other Production	2.59%	3.02%	0.43%	34,229,815	39,880,095	5,650,280
Transmission	1.38%	2.26%	0.88%	1,139,490	1,865,917	726,427
Distribution	2.50%	2.37%	-0.13%	103,532,446	97,969,879	(5,562,567)
General Plant	5.99%	4.99%	-1.00%	25,358,257	21,114,220	(4,244,037)
Total	2.93%	2.84%	-0.09%	$290,859,788	$281,734,142	($9,125,646)

Table 2. Present and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.84 percent. Depreciation expense is currently accrued at rates that composite to 2.93 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.09 percentage points.

A continued application of current rates would provide annualized depreciation expense of $290,859,788 compared with an annualized expense of $281,734,142 using the rates developed in this study. The proposed 2008 expense decrease is $9,125,646. The computed change in annualized accruals includes a

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Electric, Inc.

April 30, 2009

Attachment REW-2

2009 Technical Update

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

Statement E

UNS ELECTRIC, INC. (Excluding Black Mountain)

Current and Proposed Parameters
Broad Group Procedure

Account Description	Current Parameters: P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters: P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
362.00 Station Equipment	25.00	S4	25.00	11.54			25.00	S4	25.00	13.57		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	14.83	-9.9	-10.0	27.00	S4	27.00	13.80	-9.7	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	15.16	-9.8	-10.0	27.00	S3	27.00	15.12	-9.9	-10.0
366.00 Underground Conduit	28.00	S2	26.00	18.66	-5.0	-5.0	28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.20			23.00	S3	23.00	15.52	-0.5	
368.00 Line Transformers	23.00	S4	23.00	13.46	-5.0	-5.0	23.00	S4	23.00	13.82	-5.6	-5.0
369.OH Services - Overhead	27.00	R5	27.00	14.43			27.00	R5	27.00	13.82		
369.UG Services - Underground	27.00	R5	27.00	16.26			27.00	R5	27.00	17.43		
370.00 Meters	34.00	R3	34.00	24.14	-4.8	-5.0	34.00	R3	34.00	25.56	-3.9	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	16.64			25.00	S4	25.00	14.77		
Total Distribution Plant									25.67	14.91	-5.7	-5.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	38.00	29.03			38.00	R2	38.00	27.19		
392.C1 Transportation Equipment - Class 1	8.00	L1.5	8.00	4.00			8.00	L1.5	8.00	5.76	4.0	10.0
392.C2 Transportation Equipment - Class 2	6.00	L2	6.00	3.02			6.00	L2	6.00	3.65	7.7	10.0
392.C3 Transportation Equipment - Class 3	5.00	S5	5.00	3.28			5.00	S5	5.00	2.41	5.2	10.0
392.C4 Transportation Equipment - Class 4	8.00	S4	8.00	1.63			8.00	S4	8.00	3.11	3.3	10.0
392.C5 Transportation Equipment - Class 5	8.00	S4	8.00	6.58			8.00	S4	8.00	5.62	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	5.16			15.00	S5	15.00	9.00		
Total Depreciable									9.25	5.78	4.9	6.8
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-4.3	-4.5
TOTAL UTILITY									25.01	15.09	-4.3	-4.5

UNS ELECTRIC, INC. (Including Black Mountain)

Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Current Rates (at 12/31/2008) Investment	Current Rates Net Salvage	Current Rates Total	Proposed Rates (at 12/31/2008) Investment	Proposed Rates Net Salvage	Proposed Rates Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
Depreciable						
303.WP Misc. Intangible - WAPA Switchboard	3.13%		3.13%	2.82%		2.82%
Total Depreciable	3.13%		3.13%	2.82%		2.82%
Amortizable						
302.00 Franchises and Consents	← 25 Year Amortization →					
303.00 Miscellaneous Intangible Plant	← 15 Year Amortization →			← 15 Year Amortization →		
303.WC Misc. Intangible - WAPA Fiber Optic	← 23 Year Amortization →			← 23 Year Amortization →		
303.PC Misc.Intangible Plant - PC Software	← 5 Year Amortization →			← 5 Year Amortization →		
Total Amortizable	7.00%		7.00%	7.00%		7.00%
Total Intangible Plant	5.25%		5.25%	5.11%		5.11%
OTHER PRODUCTION PLANT						
341.00 Structures and Improvements	2.35%		2.35%	2.36%		2.36%
342.00 *Fuel Holders, Producers and Accessories*	2.53%		2.53%	2.55%		2.55%
343.00 Prime Movers	2.53%		2.53%	2.53%		2.53%
344.00 Generators	2.54%		2.54%	2.58%		2.58%
345.00 Accessory Electric Equipment	2.52%		2.52%	2.55%		2.55%
346.00 Miscellaneous Power Plant Equipment	2.58%		2.58%	2.62%		2.62%
353.00 Station Equipment	3.13%		3.13%	2.82%		2.62%
Total Other Production Plant	2.55%		2.55%	2.56%		2.56%
TRANSMISSION PLANT						
350.RW Rights of Way	2.02%		2.02%	1.91%		1.91%
352.00 *Structures and Improvements*	3.13%		3.13%	2.93%		2.93%
353.00 Station Equipment	3.15%		3.15%	3.02%		3.02%
354.00 Towers and Fixtures	5.03%		5.03%	4.89%		4.89%
355.00 Poles and Fixtures	4.08%	0.40%	4.48%	3.86%	0.38%	4.24%
356.00 Overhead Conductors and Devices	2.66%		2.66%	2.55%		2.55%
358.00 Underground Conductors and Devices	4.36%		4.36%	1.99%	0.10%	2.09%
359.00 Roads and Trails	2.02%		2.02%	1.93%		1.93%
Total Transmission Plant	3.38%	0.15%	3.52%	3.22%	0.14%	3.36%
DISTRIBUTION PLANT						
360.RW Rights of Way	2.03%		2.03%	1.95%		1.95%
361.00 Structures and Improvements	2.96%		2.96%	2.90%		2.90%
362.00 Station Equipment	4.09%		4.09%	3.84%		3.84%
364.00 Poles, Towers and Fixtures	3.76%	0.38%	4.14%	3.54%	0.34%	3.88%
365.00 Overhead Conductors and Devices	3.76%	0.37%	4.13%	3.57%	0.35%	3.92%
366.00 Underground Conduit	3.61%	0.18%	3.79%	3.49%	0.17%	3.66%
367.00 Underground Conductors and Devices	4.40%		4.40%	4.25%	0.02%	4.27%
368.00 Line Transformers	4.41%	0.22%	4.63%	4.21%	0.24%	4.45%
369.OH Services - Overhead	3.77%		3.77%	3.54%		3.54%
369.UG Services - Underground	3.75%		3.75%	3.61%		3.61%
370.00 Meters	2.96%	0.15%	3.11%	2.90%	0.11%	3.01%
373.00 Street Lighting and Signal Systems	4.04%		4.04%	3.87%		3.87%
Total Distribution Plant	3.95%	0.22%	4.17%	3.76%	0.21%	3.97%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.65%		2.65%	2.60%		2.60%
392.C1 Transportation Equipment - Class 1	12.75%		12.75%	12.35%	-0.46%	11.89%
392.C2 Transportation Equipment - Class 2	16.99%		16.99%	16.33%	-1.24%	15.09%
392.C3 Transportation Equipment - Class 3	20.21%		20.21%	19.32%	-0.94%	18.38%
392.C4 Transportation Equipment - Class 4	13.47%		13.47%	11.88%	-0.32%	11.56%
392.C5 Transportation Equipment - Class 5	12.55%		12.55%	12.33%	-1.23%	11.10%
396.00 Power Operated Equipment	6.92%		6.92%	6.53%		6.53%
Total Depreciable	11.04%		11.04%	10.56%	-0.68%	9.87%

UNS ELECTRIC, INC. (Including Black Mountain)
Current and Proposed Parameters
Broad Group Procedure

Statement E

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-3.8	-3.9
TOTAL UTILITY									26.10	16.98	-3.8	-3.9
OTHER PRODUCTION PLANT												
Nogales												
341.00 Structures and Improvements	49.00	S6	49.00	29.50			49.00	S6	49.00	40.31		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	32.63			40.00	S4	40.00	31.64		
343.00 Prime Movers	40.00	R3	40.00	26.17			40.00	R3	40.00	28.50	0.1	
344.00 Generators	43.00	S0	43.00	36.15			43.00	S0	43.00	38.26		
345.00 Accessory Electric Equipment	43.00	S6	43.00	29.39			43.00	S6	43.00	31.86		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	33.34			38.00	R1	38.00	34.33		
353.00 Station Equipment												
Total Nogales									41.42	32.23		
Black Mountain												
341.00 Structures and Improvements							2048	200-SC	38.00	37.55		
342.00 Fuel Holders, Producers and Accessories							2048	200-SC	38.00	37.55		
343.00 Prime Movers												
344.00 Generators							2048	200-SC	38.00	37.55		
345.00 Accessory Electric Equipment							2048	200-SC	38.00	37.55		
346.00 Miscellaneous Power Plant Equipment							2048	200-SC	38.00	37.55		
353.00 Station Equipment							2048	200-SC	38.00	37.55		
Total Black Mountain									38.00	37.55		

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.8: Refer to the cost of the January 2010 through March 2011 non-voluntary severance program:

a. Please confirm that APS is requesting an amount of O&M expense of $3.366 million in the current case for the January 2010 through March 2011 non-voluntary severance program. If that amount cannot be confirmed, please identify the amount of O&M expense that APS is requesting, show how it was derived and reconcile it to the information shown on JCL_WP27, page 2 of 12.

b. What is the ACC jurisdictional amount that corresponds with the $3.366 million on JCL_WP27, page 2 of 12?

Response:

a. Yes, APS is requesting that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the Test Year.

b. The ACC jurisdictional amount that corresponds with the $3.366 million is $3.128 million.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
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DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.6: Refer to JCL_WP27, page 2 of 12.

a. Please explain what the APSCCO and Grand Total amounts for each prior year, 2003 through 2010 represent.

b. Show in detail how the APS share of the Four Corner and Cholla amounts for 2010 were determined.

c. Provide the basis and support for the "41% participant recovery" factor.

d. Does APS' proposed cost amortization period start when the savings started? If not, explain fully why not.

e. Please identify when the savings started.

Response:

a. APSCO is the regulated utility Arizona Public Service Company. Grand Total is the sum of Pinnacle West and all of its subsidiaries.

b. See attachment APS14950. The percentage of ownership for Cholla and Four Corners was used to calculate APS's share of the costs. APS's ownership share is as follows:

- Four Corners Units 1-3: 100%
- Four Corners Units 4-5: 15%
- Four Corners Common: 38.44%
- Cholla Units 1-3: 100%
- Cholla Common: 63.34%

c. APS receives recovery of a portion of its A&G expenses from the other owners of the power plants that APS operates but does not own 100% of the asset. The supporting calculation is included as attachment APS14951.

d. Yes, APS is requesting that $3.366 million of the $10.099 million associated with the 2010 non-voluntary severance program remain in the test year, which represents the first year of a 3 year amortization of the severance costs.

e. The savings started during the 2010 Test Year, as described in Staff 25.5, the savings from the headcount reductions have been reflected by reducing payroll costs as if those severed employees had been gone for all 12 months of the Test Year.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.5: Severance. Refer to Mr. La Benz' direct testimony at page 25-26 concerning the non-voluntary severance program.

a. Please identify the number of positions severed by month related to the January 2010 through March 2011 non-voluntary severance program.

b. Please show in detail how the first year savings of $22.446 million was derived.

c. Please provide a breakout of the first year savings of $22.446 million by month.

d. Please identify the period covered by the "first year" referenced on page 25, lines 17-18.

e. Please show in detail how the $10.099 million of costs were recorded in each year.

f. Please explain in detail and provide supporting calculations showing exactly how the $10.099 million cost associated with severing positions through a non-voluntary severance program that was recorded charged to O&M expense in 2010 relates to the first year savings of $22.446 million.

g. How much of the first year savings of $22.446 million occurred in 2010? Please show the 2010 savings in total and provide a breakout of such savings between (1) APS O&M expense and (2) capitalized construction costs and other.

h. How much of the first year savings of $22.446 million has occurred in 2011 through September 30, 2011?

i. Is there a second and third year savings related to the January 2010 through March 2011 non-voluntary severance program? If not, explain fully why not. If so, please identify, quantify and explain the periods and annual amounts covered by the second and third year savings.

j. How much total savings from the January 2010 through March 2011 non-voluntary severance program does APS anticipate that it will have realized in the period January 1, 2010 through June 30, 2012? Please show the amount by year.

k. Did APS file a request for accounting deferrals and/or to establish a regulatory asset related to the $10.099 million cost of severing positions? If not, explain fully why not. If so, please identify and provide a copy of that request.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Response: a. During the period January 2010 through March 2011 the total number of APS/PNW regular employees was reduced by a net 259 employees. This was a combination of voluntary employee terminations and non-voluntary employee terminations, offset by employee new hires.

The month to month net change in regular APS/PNWCC employees levels is as follows:

- Jan 2010 to Feb 2010 - (37)
- Feb 2010 to Mar 2010 - (42)
- Mar 2010 to Apr 2010 - (42)
- Apr 2010 to May 2010 - (12)
- May 2010 to Jun 2010 - (4)
- Jun 2010 to Jul 2010 - (30)
- Jul 2010 to Aug 2010 - (12)
- Aug 2010 to Sep 2010 - (20)
- Sep 2010 to Oct 2010 - (14)
- Oct 2010 to Nov 2010 - +28
- Nov 2010 to Dec 2010 - (16)
- Dec 2010 to Jan 2011 - (18)
- Jan 2011 to Feb 2011 - (15)
- Feb 2011 to Mar 2011 - (25)

b. To clarify, the first year savings was $23,446,000, not $22,446,000. To the extent that an employee left the Company *prior to the end of the test year*, those wage savings are already reflected in the test year by virtue of them not being employed. The $23,446,000 savings portion of the Annualize Payroll Pro Forma related to the change in employee headcount levels and removes the expense that was in the test year for the months prior to departure so that the adjusted test year cost excludes the full 12 months of wages. Please see attachment APS14949 for the calculation of the savings.

c. The calculation of the pro forma adjustment to payroll expense was made on an employee by employee basis and was not tabulated on a monthly basis.

d. Since the Annualize Payroll Pro Forma annualizes the test year to March 2011 levels of employee head count, the first full year of savings would therefore be the 12 month period April 2011 through March 2012.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
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Response to Staff 25.5 Continued:

e. Please see the work papers JCL_WP27 pages 1 through 12 and APS's response to Staff 25.6 (b).

f. The $23,446,000 pro forma adjustment, which represents the payroll cost savings not already reflected in the test year, is based on the net reduction of 259 employees. Non-voluntary employee reductions were each paid a severance. The cost to APS of these severance costs totaled $10,099,000. The concept is that 2010 severance costs reduce future annual payroll costs. New customer rates will reflect lower payroll, but that benefit should be partially offset by the cost of obtaining that benefit.

g. None of the $23,446,000 savings actually occurred in the 2010 Test Year, which is why it is reflected as a savings adjustment to the 2010 Test Year as part of the "Annualize Payroll" Pro Forma. The Annualize Payroll Pro Forma adjusts the Test Year to reflect March 2011 employees and wage levels. The Annualize Payroll Pro Forma removes the expense that still remains in the test year for the employees prior to termination. Of the $23,446,000 savings, approximately $11,500,000 relate to APS O&M and $3,900,000 relate to APS Capital, with the remainder relating to amounts billed to participants in jointly owned facilities.

h. See APS's responses to 25.5(c) & 25.5(d)

i. See APS's responses to 25.5(c) & 25.5(d)

j. See APS's responses to 25.5(c) & 25.5(d)

k. APS did not file a request for accounting deferrals or establish a regulatory asset related to the $10,099,000. It did request, however, that the expense be amortized over a 3 year period to match the cost against the benefit.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Staff 21.6: Directors and Officers liability insurance.

a) Has the Company included any amounts in rate base for Directors and Officers liability insurance? If so, please identify the total and ACC jurisdictional amounts by account.

b) Has the Company included any amounts in operating expense for Directors and Officers liability insurance? If so, please identify the total and ACC jurisdictional amounts by account.

c) Please identify the cost and coverage for each Directors and Officers liability insurance policy that was in effect during each year 2009, 2010 and 2011.

d) Does the Company record any amounts for Directors and Officers liability insurance as prepaids? If not, explain fully why not. If so, please show the amounts for January 1, 2010 through the present.

Response:

a) No, premiums for Directors and Officers liability insurance are expensed during the period in which the policy is in effect (see response b), not capitalized.

b) Yes, in 2010 the Company included $1,170,354 Total Company and $1,099,366 ACC Jurisdiction in operating expenses which was recorded to FERC account 9250000.

c) The Company maintained a deductible of $2,500,000 for each of the years referenced. The following is a breakdown of coverage and premiums for each policy carried in these years:

2009

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$514,475
EIM	$10,000,000	$151,200
Zurich	$15,000,000	$155,925
RLI	$15,000,000	$93,555
Twin City Fire	$15,000,000	$80,100

Witness: Jim Hatfield

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 12, 2011

Response to Staff 21.6 continued:

2010

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$657,354
Chubb (Federal Insurance)	$15,000,000	$135,000
Zurich	$15,000,000	$103,500
AXIS	$15,000,000	$76,500
EIM	$10,000,000	$54,000
ACE	$15,000,000 (Side A Only)	$81,000
Arch	$15,000,000 (Side A Only)	$63,000

2011

Insurance Carrier	Coverage Amount	Annual Premium
AEGIS	$35,000,000	$617,947
Chubb (Federal Insurance)	$15,000,000	$141,000
Zurich	$15,000,000	$108,100
AXIS	$15,000,000	$79,900
EIM	$10,000,000	$56,400
ACE	$15,000,000 (Side A Only)	$82,500
Arch	$15,000,000 (Side A Only)	$65,800

d) The Company records premiums as an expense for the year in which coverage applies. Accordingly, all premiums incurred for the 2010 policy year were expensed in that calendar year.

Witness: Jim Hatfield

ARIZONA CORPORATION COMMISSION
STAFF'S NINETEENTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 19.17: Refer to the response to STF 15.20.

a) Identify which lower priority projects were cancelled.

b) Please identify the "certain employee groups" for which base compensation was maintained in 2009 versus 2008.

c) What exactly was done to produce the vegetation management savings of $400k?

d) What exactly was done to produce the $1.3 million savings for pole line hardware and related equipment?

e) What exactly was standardized for fossil plant operations to produce the claimed $3.5 million savings?

f) What fossil plant staffing was reduced and how many full time equivalent (FTE) positions were cut related to the $3.1 million claimed savings?

g) Explain exactly what is meant by wage escalation being "absorbed" into a department and how that produces the claimed savings.

h) What exactly were the Energy Delivery O&M improvements that resulted in the $1.2 million of claimed savings?

i) What exactly were the Energy Delivery Tech and GIS mapping department improvements that resulted in the claimed savings of $1.0 million?

j) What were the IT department staff and contractor reductions (in FTEs) that resulted in the claimed savings?

k) Which IT lesser priority work was eliminated?

Response:

a) Interest savings were calculated from capital project cash flow savings from either lower costs or cancelled projects. While the majority of cash flow savings were the result of projects being completed at a lower cost than anticipated, the specific projects that were cancelled consisted of:

   a. Various facilities projects cancelled at CHQ, totaling $4.5M in 2010. This represented projects on several floors that were planned for upgrading to current standards for furniture, flooring, remodeling, re-wiring, electrical, patching, painting, and technology wiring.

   b. Various facilities projects cancelled at Energy Delivery Division locations, totaling $1.5M in 2010. This

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OCTOBER 6, 2011

Response to Staff 19.17 Continued:

represented projects at a variety of locations across the state of the same type and nature as described in the response to a) above.

b) As detailed in the letter dated March 18, 2009 on our compliance filing regarding 2009 cost management efforts, the employee groups for which base compensation was impacted included all officers, senior managers and all other management personnel. It also included reduced merit increases for non-union frontline employees. Attached is the March 18, 2009 letter as APS14884.

c) Within the supply chain area, standardized procurement practices were established and implemented to improve planning, procuring, warehousing and delivery of materials and services. Specific activities included:

   a. For the vegetation management area savings, a contract renegotiation process was undertaken based on a detailed analysis and breakdown of the contract rate structure. As a result of discussions with the incumbent supplier, contract concessions were attained in several areas including general liability insurance costs and worker compensation costs, which totaled to $400K for 2010.

   b. For the Energy Delivery pole line hardware and related equipment area savings, a comprehensive strategic sourcing analysis was conducted on some 280 items within our warehouses procured from a variety of suppliers. As a result of this sourcing process, reduced costs were achieved from suppliers in a variety of ways, including by establishing set margins based on spend volume, reducing freight costs by using alternative means, reducing the quantity of suppliers to concentrate the spend volume, dealing directly with manufacturers instead of using distributors and using national pricing agreements and index pricing with set margins, all of which totaled to $1.3M in 2010.

d) See c) above.

e) As presented in Mark Schiavoni's testimony on pages 24-26, the standardization was of the many and varied processes at each of the fossil plants. This standardization of processes

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Response to Staff 19.17 Continued:

enabled the plants to become more cost effective and efficient. Historically, the plants had been run as individual entities rather than as an integrated fleet. A fossil operations model was established to move to a one-fleet mind-set. This model consists of a comprehensive playbook of how Fossil Generation will operate and conduct business. It represents a proven way of managing and doing business that will allow Fossil Generation to align priorities, standardize on best practices, sustain results, and continuously improve operations. During 2010, over 100 Policy, Process and Procedure documents were developed and implemented. These processes and documents are categorized under five main groups:

a. Safety effectiveness
b. Workforce effectiveness
c. Environmental commitment
d. Operational excellence
e. Asset management

f) As indicated in our response to Staff 15.20, these reduced fossil staffing costs occurred at Cholla, Four Corners, and our other fossil areas. While full time equivalent positions are not specifically tracked within the company, employee counts by regular, temporary and contract employee groups are tracked. The savings identified in Staff 15.20 for the Fossil area was the result of over 100 regular employee positions being reduced in 2010, with the majority of those occurring at the Four Corners power plant, the savings of which totaled \$3.1M in 2010.

g) Wage escalation costs being absorbed by a department means that the particular department is not receiving additional budgeted funds to cover the additional costs associated with the wage escalation. Therefore, the department must find savings across its other activities to offset the wage escalation cost increase.

h) As presented in Daniel Froetscher's testimony on pages 18-20, Energy Delivery has had a concerted focus on cost improvement over the last several years. This improvement effort has included attention on work prioritization, work scheduling, work load, overtime costs, third party contractors, and process improvements such as the SOAR initiative. While these changes have lowered costs associated with capital projects, they have also improved the efficiencies

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Response to Staff 19.17 Continued:

of several operations and maintenance departments. Two of the primary departments that focus on operational activities, the ED Operations and Maintenance Department and the ED Technology and GIS (Geographical Information System) Department, were able to gain cost reductions through these many process and efficiency improvements during 2010. More specifically, the ED Operations and Maintenance Department was able to gain efficiencies of $1.2M in 2010 by reducing overtime, reducing contractor work and stretching out the filling of vacancies. The ED Technology and GIS Department was able to gain efficiencies of $1.0M in 2010 by re-evaluating its processes and workload and reducing its workforce.

i) See h) above.

j) As indicated in response to f) above, while full time equivalent positions are not specifically tracked within the company, employee counts by regular, temporary and contract employee groups are tracked. The savings identified in Staff 15.20 for the IT area was the result of over 100 contractor and regular employee positions being reduced in 2010, with the majority of those occurring from reduced contractor positions.

k) As indicated in the response to Staff 15.20, most work processes and work activities performed by the IT Department were re-evaluated in 2010 and many work activities were reduced. Work requests that were reduced primarily included (but not exclusively) requests for development of new applications and enhancements to existing applications of a less critical nature to the supply and distribution of electricity to our customers, as well as requests for replacements of existing equipment that were beyond manufacturers' specifications in terms of technology support but still functional.

Witness: Don Robinson

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.21: Refer to JCL_WP30, page 5 of 63. What specific non-plant maintenance was done in 2005 that caused the amounts in that year to be so much higher than in each and every other year?

Response: Year 2005 was $900,000 higher than other years because of $657,000 in incentive charged in that year plus a higher than average payroll accrual charged that year to department 9960 of $235,000 compared to the six year average of $55,000.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SEVENTH SET OF DATA REQUESTS
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DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.11: Four Corners Units 4&5 acquisition – impacts on APS' filing.

a) Please identify, quantify and explain each component of APS' filing that is impacted by, or reflects an assumption that the proposed acquisition by APS of Southern California Edison's ownership in those units would be consummated.

b) For each component or aspect of APS' filing that is based on, or effectively reflects that the proposed acquisition by APS of Southern California Edison's ownership in those units would be consummated, please show the impact on APS' filing if that proposed transaction were not to be consummated.

c) Please explain and quantify the impacts of the proposed acquisition of Four Corners Units 4 and 5 on each of the following components of APS' filing, as well as any others that have been affected by that proposed acquisition:

1. Rate base – show by component
2. Mine reclamation cost recovery
3. Dismantlement cost recovery
4. Depreciation rates
5. Base cost of fuel and purchased power

Response: (a) – (c) The attached file APS14988 shows the remaining net book value of the Four Corners assets as of December 31, 2010. See Direct Testimony of Ronald E White, page 10 for a description of how depreciation and dismantlement costs were addressed in consideration of the proposed acquisition by APS of Southern California Edison's ownership in those units. In addition, the coal mine reclamation pro forma takes into consideration the remaining lives of the Four Corners units. If this transaction is not consummated these costs would still need to be recovered, although the pattern of recovery may be different. They could be recovered over the years 2012-2016, which represents the likely remaining life of Four Corners absent the APS acquisition of SCE's interest, or some other reasonable period of time as determined by the Commission. See Staff 22.9 for a discussion related to fuel impacts.

Witness: Jay La Benz

ARIZONA PUBLIC SERVICE
Depreciation Reserve Summary
Steam Production
As of December 31, 2010

Four Corners Units 1-3		Recorded Reserve	
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	40,683,091	22,130,773	18,552,319
312.00 Boiler Plant Equipment	242,101,914	166,321,891	75,780,023
314.00 Turbogenerators	50,183,693	34,950,798	15,232,896
315.00 Accessory Equip	24,333,485	14,311,157	10,022,328
316.00 Misc Power Plant Equip	11,655,314	5,718,804	5,936,510
	368,957,497	243,433,422	125,524,075

Four Corners Units 4-5			
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	11,882,266	7,361,654	4,520,612
312.00 Boiler Plant Equipment	118,062,055	75,799,402	42,262,653
314.00 Turbogenerators	21,183,385	10,435,941	10,747,444
315.00 Accessory Equip	11,137,088	7,001,791	4,135,297
316.00 Misc Power Plant Equip	3,614,952	2,053,080	1,561,872
	165,879,746	102,651,868	63,227,878

Four Corners Common			
Account Description	Original Cost	Total Reserve	Net Book Value
311.00 Structures & Improvements	4,983,659	2,342,778	2,640,881
312.00 Boiler Plant Equipment	15,238,147	7,855,190	7,382,958
314.00 Turbogenerators	1,987,500	1,288,114	699,386
315.00 Accessory Equip	4,593,380	1,839,483	2,753,897
316.00 Misc Power Plant Equip	10,452,621	4,142,487	6,310,134
	37,255,307	17,468,052	19,787,256
Total Four Corners	572,092,550	363,553,342	208,539,209

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
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DOCKET NO. E-01345A-11-0224
OCTOBER 25, 2011

Staff 25.22: Four Corners Units 1-3 maintenance.

a. Refer to JCL_WP30, pages 2 and 3 of 63. Please provide APS' specific plans and budgets for overhauls on Four Corners Units 1, 2 and 3, in each year, 2011 and 2012.

b. Please provide APS' actual expense for overhauls on Four Corners Units 1, 2 and 3 in 2011 through September.

c. Refer to JCL_WP30, pages 2 and 3 of 63. Please provide APS' specific plans and budgets for Routine Maintenance on Four Corners Units 1, 2 and 3, in each year, 2011 and 2012.

d. Please provide APS' actual expense for Routine Maintenance on Four Corners Units 1, 2 and 3 in 2011 through September.

e. Given the expectation that APS will retire Four Corners Units 1, 2 and 3 in 2012, please explain how the planned retirement will affect the $5.085 million, $5.142 million and $6.547 million maintenance expense for Four Corners Units 1, 2 and 3 that APS is requesting.

f. Does the overhaul and routine maintenance cycle typically cease with a fossil unit after it has been retired? If not, explain fully why not.

g. What amounts of Overhaul and Routine Maintenance does APS project for each unit of Four Corners Units 1, 2 and 3 beyond 2012? Explain and provide the projections.

    1. If APS has different projections for Units 1-3 post-2012 maintenance depending upon whether those units are retired in 2012 or not, please identify, explain and provide the alternative versions.

Response:

(a) Please see APS14967, attached.

(b) Please see APS14967, attached.

(c) Routine Maintenance costs are related to the continuing preventative and corrective maintenance, inspections and emergent repairs at the plants. Thus, unlike outages, there is no specific and/or pre-defined work scope for all of the activities that are performed under Routine Maintenance. Please see attachment to STF25.18 for 2011 Budget and 2012 Forecast of Routine Maintenance.

(d) APS's actual routine maintenance on Four Corners Units 1, 2 and 3 in 2011 through September are $3,227K, $2,328K, and $2,642K, respectively.

Witness: Jay La Benz/Mark Schiavoni

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY FIFTH SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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OCTOBER 25, 2011

Response to Staff 25.22 Continued:

(e) APS's deferral order proposed in Docket No. E-01345A-10-0474, would net any reduced costs of Units 1-3 with the acquisition of SCE's share of Units 4-5, thus providing customers the benefit of any cost offsets. Also, as stated in that Docket, Units 1-3 could continue running past the acquisition date to (1) allow for a transition period and (2) if favorable market conditions exist, APS could sell the output as off-system sales, crediting margins to customers through the PSA.

(f) The normal overhaul and ongoing maintenance cycles would cease after a fossil unit has been retired. However, costs will be incurred after a plant ceases operation in order to perform activities to secure the unit in a safe condition until dismantlement and decommissioning.

(g) Please see response to 25.22(e) and (f).

(g)(1) In the event Units 1-3 remain in-service beyond 2012, maintenance costs for those units would increase and would likely reflect amounts similar to those submitted in the Fossil Maintenance Normalization proforma. If a deferral order is granted maintenance costs for Units 1-3 would influence the amount of such deferral, see response to 25.22 (e).

Witness: Jay La Benz/Mark Schiavoni

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 14, 2011

Staff 1.36: Edison Electric Institute dues.

a. What amount of dues for EEI has the Company requested? Show the amounts, by account.
b. Provide copies of the Edison Electric Institute dues invoices for the years 2009, 2010 and 2011.
c. Include invoices for each EEI committee any subgroup.
d. Identify the portion for EEI dues and for each EEI group for lobbying activities that has been recorded into below-the-line accounts.

Response:

a. The company has requested $619,143 of EEI membership dues recorded in account 930.2. Also included in the request are subcommitte dues attched in part c below. UARG membership dues of $157,896 recorded in account 930.2. USWAG membership dues of $34,763 recorded in account 930.2. APLIC membership dues of $2,500 recorded in account 593.

b. Attached as APS14207, APS14208, and APS14209 are the requested invoices.

c. Attached as APS14210, APS14211, and APS14218 are the requested invoices.

d. Lobbying expenses for EEI of $132,329 were recorded into below-the-line accounts during the Test Year. Also included in the EEI dues are donations of $30,000 that were recorded into below-the-line accounts during the Test Year.

Witness: Jay La Benz

2011 Allocation

	Total	O&M 00-9302-00 620	Lobbying 00-4264-00 430	Charitable 00-4261-00 895	2011 Split O&M	2011 Split Lobbying
Regular Activities	705,660	557,471	148,189		79.00%	21.00%
Industry Issues	70,566	45,868	24,698		65.00%	35.00%
Mutual Assistance Prog	5,000	5,000				
2011 Contribution	30,000			30,000		
	811,226	608,339	172,887	30,000		

2010 Allocation

	Total	O&M 00-9302-00 620	Lobbying 00-4264-00 430	Charitable 00-4261-00 895	2010 Split O&M	2010 Split Lobbying
Regular Activities	678,611	570,033	108,578		84.00%	16.00%
Industry Issues	67,861	44,110	23,751		65.00%	35.00%
Mutual Assistance Prog	5,000	5,000				
2010 Contribution	30,000			30,000		
	781,472	619,143	132,329	30,000		

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
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DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.5: Edison Electric Institute.

a) Please provide the EEI budget for each year 2008, 2009, 2010 and 2011.

b) Please provide the EEI financial statements for each year 2008, 2009, 2010 and 2011.

c) Does APS have any information breaking out EEI core dues activities by NARUC operating expense category, i.e., legislative advocacy; legislative policy research; regulatory advocacy; regulatory policy research; advertising; marketing; utility operations and engineering; finance, legal planning and customer service; public relations; and other? If not, explain fully why not. If so, please provide the most current information APS has.

Response:

a) APS does not receive copies of EEI's budget.

b) APS does not receive copies of EEI's financial statements.

c) EEI does not prepare a schedule of expenses by NARUC Category. Instead EEI provides a copy of a letter that identifies the percent of dues spent on legislative advocacy, which APS previously provided in response to Staff 1.36 as APS14209.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
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DOCKET NO. E-01345A-11-0224
OCTOBER 27, 2011

Staff 27.7: <u>Accumulated Deferred Income Taxes</u>. Referring to the originally filed APS adjustments for post test year plant, by type of plant, and to the updated amounts that APS provided in response to STF 6.55, please provide the Total Company and ACC Jurisdictional amounts (1) as of 3/31/2012 and (2) identify the changes APS estimated to occur for the period April 1, 2012 through June 30, 2012.

Response:

(1) Please see the APS response to Staff 15.9 for 3/31/2012 Total Company Accumulated Deferred Income Taxes (ADIT). The corresponding ACC jurisdiction of these amounts are as follows:

- Solar: $2.476 Million
- Fossil: $12.344 Million
- Nuclear: $30.226 Million
- Distribution and General & Intangibles: $1.878 Million

(2) For Fossil Generation, Nuclear Generation, and Distribution and General and Intangible Plant, the only change in ADIT for the referenced period is continued book and tax depreciation differences on plant in service at 12/31/2010. Consistent with the RES treatment, permitted by Decision No. 71448, Solar Generation ADIT change for the referenced period includes book and tax depreciation on additions during the post test year period.

Witness: Jay La Benz

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DOCKET NO. E-01345A-11-0224
SEPTEMBER 21, 2011

Staff 15.7: Accumulated Deferred Income Taxes (ADIT).
For ADIT, show the month-end balances by component and in total based on current monthly actual (if available) or projected (if actual is not yet available) information showing all monthly balances for each month, July 2011 through March 2012, and the resultant estimated ADIT balance at March 31, 2012.

Response: Inclusion of any such estimated projections of deferred taxes as a rate base offset may be deemed by the IRS as inconsistent with the historical Test Year method generally used for cost of service and ratemaking purposes. Without guidance from the IRS that explicitly allows such inclusions, APS believes using such methodology would not be appropriate and could result in extremely unfavorable tax consequences to the Company and its customers. That said, please see schedule attached as APS14830.

Witness: Jason La Benz

ARIZONA PUBLIC SERVICE COMPANY
DEFERRED TAXES
SUPPORTING SCHEDULE FOR B-1
(dollars in thousands)

ACCOUNT DESCRIPTION	Actuals Increase (Decrease) RATE BASE 7/31/11	Actuals Increase (Decrease) RATE BASE 8/31/11	Forecast Increase (Decrease) RATE BASE 9/30/11	Forecast Increase (Decrease) RATE BASE 10/31/11	Forecast Increase (Decrease) RATE BASE 11/30/11	Forecast Increase (Decrease) RATE BASE 12/31/11	Forecast Increase (Decrease) RATE BASE 1/31/12	Forecast Increase (Decrease) RATE BASE 2/29/12	Forecast Increase (Decrease) RATE BASE 3/31/12
Total Deferred Taxes per General Ledger	$ (1,819,235)	$ (1,887,398)	$ (1,888,657)	$ (1,893,263)	$ (1,891,763)	$ (1,893,834)	$ (1,895,722)	$ (1,891,506)	$ (1,881,995)
Exclude									
Reg Asset-Power Supply Adjustor Mark to Market	(24,929)	(24,929)	(18,418)	(17,861)	(18,042)	(17,792)	(17,719)	(17,882)	(18,323)
Reg Asset-Transmission Vegetation Management	(17,857)	(17,747)	(17,701)	(17,685)	(17,690)	(17,683)	(17,680)	(17,687)	(17,708)
Reg Asset-Unamortized Loss on Reaquired Debt	(8,346)	(8,187)	(8,120)	(8,097)	(8,105)	(8,094)	(8,089)	(8,100)	(8,130)
Option II Benefits (Includes Reg Asset and Def Comp)	4,272	3,879	3,712	3,653	3,672	3,646	3,640	3,653	3,689
Reg Asset-Demand Side Management	(4,351)	(2,806)	(2,151)	(1,922)	(1,997)	(1,894)	(1,876)	(1,916)	(2,025)
Reg Liab-Renewable Energy Standard	20,208	21,054	21,412	21,538	21,497	21,553	21,580	21,520	21,359
Reg Liab-Power Supply Adjustor	9,129	1,041	(2,391)	(3,588)	(3,198)	(3,736)	(3,703)	(3,776)	(3,974)
Renewable Energy Incentives	47,539	53,456	55,966	56,841	56,556	56,950	57,066	56,807	56,107
Mark to Market	74,908	64,472	82,448	81,877	82,063	81,806	81,730	81,900	82,362
OCI-Pension Taxes	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123	22,123
Superfund	1,758	1,711	1,691	1,684	1,686	1,683	1,682	1,685	1,694
Other	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039	1,039
Total Deferred Taxes	$ (1,944,729)	$ (2,002,501)	$ (2,028,266)	$ (2,032,865)	$ (2,031,367)	$ (2,033,434)	$ (2,035,202)	$ (2,031,256)	$ (2,022,162)

Attachment RCS-3
Page 84 of 86

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY SECOND SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
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DOCKET NO. E-01345A-11-0224
OCTOBER 14, 2011

Staff 22.9: <u>Base cost of fuel</u>.

a) Please update Attachment PME-3 and PME-4 using current information on fuel costs projected for 2012. Please provide the updated results in Excel.

b) Please provide quantifications and workpapers for the items in footnotes 1 through 7 on Attachment PME-3:

1) ISFSI expense
2) Coal reclamation costs
3) Fuel costs associated with long-term tolling arrangements
4) Native load head liquidation costs
5) Fixed capacity contract costs
6) Above market purchases of renewable that are recovered through RES
7) Generation associated with Company owned facilities

Response:

a) APS is in the process of updating the base fuel and purchased power pro forma adjustment and will provide it upon its completion. We anticipate having this update available at the Rate Case Technical Conference on October 27, 2011.

b)

1) Please see PME_WP2, page 1 of 3, for the test year amounts of nuclear ISFSI amortization excluded from the base fuel rate.

2) Please see PME_WP2, page 1 of 3, for the test year amounts of coal reclamation costs excluded from the base fuel rate.

3) Please see PME_WP5, page 2 of 7, for the amount of gas fuel expense associated with long-term tolling arrangements included in the base fuel rate.

4) Please see PME_WP5, page 2 of 7, for the current contract cost vs. market value of the native load power hedges (labeled "SE06 Hedge MTM") included in the base fuel rate.

Witness: Pete Ewen

ARIZONA CORPORATION COMMISSION
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OCTOBER 14, 2011

Response to Staff 22.9 continued:

5) Please see PME_WP5, page 2 of 7, for the amount of fixed capacity contract costs (labeled "Demand Cost" or "Demand") included in the base fuel rate.

6) Please see PME_WP5, page 2 of 7, for the amount of above market purchases of renewable energy that are recovered through RES (labeled "Above-Market Premiums") included in the base fuel rate.

7) Please see APS14923, attached.

Supplemental Response to Staff 22.9:

a) Attached are the supplemental base fuel updated and associated workpapers:

- Attachment PME-3 as APS14926
- Attachment PME-4 as APS14927
- Workpaper PME_WP1 as APS14928
- Workpaper PME_WP2 as APS14937
- Workpaper PME_WP5 as APS14929
- Workpaper PME_WP6 as APS14930
- Workpaper PME_WP9 as APS14931

Witness: Pete Ewen

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-4
Copies of Confidential APS' Responses to Data Requests and Workpapers Referenced in the Direct Testimony and Schedules of Ralph C. Smith

****APS Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
Staff 19.14	ADIT on post test year plant	Yes	4	2 - 5
Staff 19.15	APS will have a [*BEGIN CONFIDENTIAL*] [*END CONFIDENTIAL*]; tax loss carryforwards and income tax expense	Yes	3	6 - 8
Staff 27.1	Actuarial valuation of pension and OPEB costs presented on May 20, 2011 by Towers Watson	Yes	4	9 - 12
Staff 9.4	Expense in test year related to APS' forensic investigation of Department of Energy funded projects	Yes	1	13
Staff 9.7	Expense in test year related to investigation of of DOE grant-funded projects	Yes	1	14
Staff 9.8	Investigation of DOE grant-funded projects is complete	Yes	1	15
Staff 9.9	Documentation referenced in Deloitte & Touche audit workpapers not provided	Yes	1	16
Staff 19.21	Expenses for investigation into grants and government awards removed from test year	Yes	2	17 - 18
Staff 20.4	Expenditures for grant-funded projects	Yes	3	19 - 21
Staff 21.2	External advertising retainer contract (response without copy of contract)	Yes	1	22
Staff 22.2	Incentive compensation for years 2008 - 2010	Yes	2	23 - 24
Staff 20.8	Incentive compensation allocations for officers, front line and non-senior management	Yes	5	25 - 29
Staff 1.16	Description of retirement and incentive compensation programs	Yes	28	30 - 57
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DOCKET NO. E-01345A-11-0224
OCTOBER 6, 2011

Staff 19.14: ADIT on post test year plant. Refer to the response to STF 15.13.

a) Explain fully and in detail and cite all provision of the tax law, treasury regulations, IRS revenue rulings etc. relied upon for APS' opinion that reflecting ADIT that is directly related to post test year plant might in any way be inappropriate.

b) Please provide a draft of the guidance that APS would need to seek from the IRS to explicitly allow post test year ADIT to match post test year plant amounts being reflected in rate base.

c) Please describe fully how APS would propose to reflect for ratemaking purposes the post test year ADIT that is directly related to post test year plant being included in rate base.

d) Identify, quantify and explain in detail all tax loss carry forwards that exist for APS at December 31, 2010, and their estimated use and impact on 2011 bonus tax depreciation.

e) Provide all APS calculations of projected or estimated use of tax loss carry forwards that exist at December 31, 2010.

f) Provide all APS calculations of projected or estimated use of tax loss carry forwards that APS expects would exist at December 31, 2011 with APS taking 2011 bonus federal tax depreciation in 2011.

g) How were the 37%, 63%, 90%, 18.5%, and 81.5% on APS14831 page 2 of 2 derived? Provide explanations and supporting calculations.

Response:

a) Accelerated depreciation was enacted by Congress with the general intention of encouraging economic growth and investment by providing a capital subsidy to those businesses investing in certain machinery and equipment. The immediate provision of the benefits of accelerated depreciation to utility customers (via lower current rates) was generally seen as contrary to the intended purpose of the incentive. To prevent this outcome, normalization of accelerated depreciation is required for ratemaking purposes by IRC Section 168(f)(2) and (i)(9) and former IRC Section 167(l).

The service continues to rely on the IRC §167(l) regulations in resolving issues arising under the MACRS normalization requirements.

Witness: Jay La Benz

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Response to Staff 19.14 Continued:

For depreciation, a utility is generally considered in compliance with the normalization rules if it meets three requirements: First, it must account for the variation between straight-line cost of service depreciation and accelerated tax deprecation in the ratemaking process by making an adjustment to a reserve account - that is, it must include a deferred tax expense component in cost of service. Second, while the deferred tax liability associated with accelerated tax depreciation (the reserve account) can be used as a rate base reduction, the amount of the rate base reduction is limited. Finally, the reserve account must only be reversed for certain, specified events.

The proposal regarding ADIT associated with post-test year plant implicates the second of the above-mentioned requirements - the rate base reduction limitation.

Treasury Regulation §1.167(l)-1(h)(6)(i) provides that "...a taxpayer does not use a normalization method of accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's return is applied, or which is treated as a no-cost capital in those rate cases in which the rate of return is base on cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking."

This regulation section provides that a taxpayer may not exclude from rate base a reserve for deferred taxes in excess of the amount of reserve determined in computing tax expense in accordance with the normalization requirements. Thus, it requires that the reduction in rate base be synchronized with the quantity of deferred taxes reflected in cost of service. The Company is concerned that the incremental ADIT associated with post-test period plant fails to satisfy this requirement insofar as it was never included in cost of service.

This regulation was drafted as a response to the ratemaking practice of computing tax expense for cost of service purposes utilizing historical information (e.g., 2010 historic test year), while computing the reserve for deferred income taxes allowable as a reduction from rate base based on projected data (e.g., deferred taxes for post test year).

Witness: Jay La Benz

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Response to Staff 19.14 Continued:

In the view of the IRS, this created two problems. First, assuming a financially healthy utility, the amount excluded from rate base was greater than the reserve for deferred tax at the end of the historical period. Failure to allow an investment return on this excess of the excluded amount over the amount of the reserve for the historical period resulted in flow-through of the benefits of the projected reserve accrual. Second, even though any projected increase in the reserve for deferred taxes would accrue over time, the entire amount expected to be in the reserve at the end of the future period was excluded from rate base. Excluding the full projected amount, even if ratemaking tax expense was computed using the same projections, resulted in denying a return on a greater amount that the utility was projected to have on hand at any particular time over this future period. Section 1.167(l)-1(h)(6)(i) deals with the first problem, that of *consistency,* while 1.167(l)-1(h)(6)(ii) addresses the second problem, that of *timing*" (PLR 9029040).

The amount of the reserve excluded from rate base must be computed on the same period used to determine ratemaking tax expense. If a historical period is used to determine depreciation for federal income tax expense for ratemaking purposes, the maximum amount of the reserve that can be excluded from rate base is the amount of such reserve at the end of the historical period.

Failure to comply with the normalization rules can subject a utility to significant penalties, including the forfeiture of accelerated depreciation deductions for the utility's public utility property. Taxpayers are obligated by regulation to report a normalization violation to the IRS within 90 days.

b) A draft of the guidance (a Private Letter Ruling) that APS would need to seek from the IRS has not yet been prepared, and could take several months to draft. Additionally, outside tax counsel would be needed to properly draft and file such a request for guidance. APS believes that the associated expenditures should not be made until it becomes readily apparent that no other options are available.

c) With regard to the reflection of ADIT associated with post-test year plant, APS proposes one of two options:

Witness: Jay La Benz

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Response to Staff 19.14 Continued:

1) Allow post test year additions in a manner consistent with the 2009 rate settlement. That is, do not reduce the post test year plant additions for estimated post test year ADIT. Aside from being consistent with prior practice, this will clearly not violate the normalization rate base reduction limitation.

2) Permit APS to use a complete future test period ending June 30, 2012 for all rate case items. Not only would the information upon which rates are established be more representative of the conditions during the period in which rates would be in effect, because all components of the rate case would then employ the same basis of reporting, there would be no concern regarding the application of the normalization rules.

d) No federal tax loss carry forwards existed for APS at December 31, 2010.

e) As stated above, no federal tax loss carry forwards existed for APS at December 31, 2010.

f) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

g) The percentages on APS14831 page 2 of 2, provided in response to Staff 15.13, represent estimated ranges of post test year plant additions eligible for either 100-percent or 50-percent bonus tax depreciation. These amounts were estimated based upon prior experience with bonus depreciation from 2001 to present.

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Staff 19.15: Tax loss carry forwards and income tax expense. Refer to the response to STF 15.13, which mentions that APS expects tax loss carry forwards.

a) Did APS pay any federal income tax for 2010? If not, explain fully why not. If so, please identify the amount paid.

b) Did APS' parent company pay any federal income tax for 2010? If not, explain fully why not. If so, please identify the amount paid.

c) Does APS anticipate having to pay any federal income tax for 2011? If not, explain fully why not. If so, please identify the amount APS expects to pay and include supporting calculations.

d) Does APS anticipate having to pay any federal income tax for 2012? If not, explain fully why not. If so, please identify the amount APS expects to pay and include supporting calculations.

e) Does APS' rate filing reflect any claim for current federal income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

f) Does APS' rate filing reflect any claim for deferred federal income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

g) Does APS' rate filing reflect any claim for current Arizona state income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

h) Does APS' rate filing reflect any claim for deferred Arizona state income tax expense? If not, explain fully why not. If so, please identify the amount and show in detail how it was calculated.

i) Can APS have a positive current federal income tax expense if no federal income taxes are being paid for the year and APS has a net operating loss carry forward? If not, explain fully why not. If so, explain exactly how that can occur.

Response: a) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

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Response to Staff 19.15 Continued:

b) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

c) No. As a result of 100-percent bonus depreciation, APS will have a tax net operating loss in 2011.

d) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

e) Yes, APS's rate filing reflects a claim for current federal *income tax expense. APS rate filing is based upon the 2010* historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million.

f) Yes, APS's rate filing reflects a claim for deferred federal income tax expense. APS rate filing is based upon the 2010 historical test year. *Line 15 of JCL_WP25 shows the actual* test year tax expense of $175.4 million. This actual test year tax expense contains federal deferred tax expense of $208.4 million.

g) Yes, APS's rate filing reflects a claim for current state income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million. The actual test year tax expense contains a current state tax expense of $17.9 million.

h) Yes, APS's rate filing reflects a claim for deferred state income tax expense. APS rate filing is based upon the 2010 historical test year. Line 15 of JCL_WP25 shows the actual test year tax expense of $175.4 million. The actual test year tax expense contains a deferred state tax expense of $16.9 million.

i) Yes. Income tax expense for financial accounting and ratemaking purposes is generally based upon accrual accounting principles. Income tax liability reported on a federal income tax return is based upon actual cash taxes paid. As such, material differences will arise.

Witness: Jay La Benz

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Response to Staff 19.15 Continued:

The Internal Revenue Code provides certain specific rules for the determination of taxable income. The use of these rules means that a utility's income tax expense for financial accounting and ratemaking purposes generally will not be the same as the income tax liability shown on its tax return. Moreover, the ACC has required the full tax normalization of these and other items since at least 1983. See Decision No. 53761.

If a public utility commission uses the utility's Federal income tax liability as shown on the utility's income tax return for income tax expense for ratemaking purposes, the commission is using a "flow-through" method of accounting for taxes. Section 168(f) of the Internal Revenue Code requires that a regulated public utility use a "normalization" method of accounting in order to qualify for certain accelerated tax benefits. "Flow-through" is explicitly not allowed.

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Staff 27.1: Pension/OPEB deferral.

a) Are any of the amounts for pensions and OPEBs in JCL_WP35 supported by the actuarial reports that were provided in response to Pre-filed 1.23? If so, please reconcile the amounts for pensions and OPEBs in JCL_WP35 to such actuarial reports.
b) Please provide the actuarial reports supporting the 2011 and 2012 pension and OPEB amounts in JCL_WP35.
c) What is the "SEBRP" in JCL_WP35?
d) Does the SEBRP in JCL_WP35 have any relation to the Supplemental Executive Retirement Benefits Plan mentioned in APS witness Guldner's direct testimony at page 6, lines 25-27? If not, explain fully why not. If so, please identify the relationship.
e) Identify, quantify and explain exactly how much of the pension/OPEB deferral amount of $26,219,162 on JCL_WP35 relates to the Supplemental Executive Retirement Benefits Plan, and provide supporting calculations.
f) Does APS believe that Section IX of the Settlement Agreement in Docket No. E-01345A-08-0172 or Order No. 71448 authorized APS to defer costs for the Supplemental Executive Retirement Benefits Plan? If not, explain fully why not. If so, explain fully and provide the supporting documentation.
g) Referring to JCL_WP35, page 4 of 9 and Settlement Agreement page 17, Section IX, Pensions and OPEB Deferrals. Does APS agree that the $23.949 million in Settlement Agreement paragraph 9.3 is the same as the $23,948,768 on JCL_WP35, page 4 of 9 and only includes the $17,228,847 for pension and $6,719,921 for OPEB, and does include cost for the Supplemental Executive Retirement Benefits Plan or for the "Misc. Expense" line items? If not, explain fully why not.
h) Does the $29,464,689 pension amount or $20,703,241 OPEB amount on JCL_WP35, page 3 of 9 include any amounts that would correspond to the "Misc. Expense" line item on JCL_WP35, page 4 of 9? If so, please identify the "Misc. Expense" amounts included in those figures. If not, explain fully why not.
i) Refer to JCL_WP35, page 3 of 9. Provide the most current Towers Perrin information on Pension and OPEB that corresponds to the Pension and OPEB amounts on JCL_WP35, page 3 of 9. This includes the "final 2011 calc" mentioned on that workpaper as well as any subsequent corrections, revisions or adjustments.

Witness: Jay La Benz

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Staff 27.1 Continued:

j) Does APS have any estimates or projections of its 2012 pension or OPEB cost? If not, explain fully why not. If so, please provide the most current projections and estimates.
k) On JCL_WP35, page 2 of 9, why did APS assume that the 2012 pension and OPEB amounts were identical to the 2011 estimates?
l) Please identify the amount and date of pension funding payments for each year, 2008 through 2011 to date.
m) Please identify the amount and date of OPEB funding payments for each year, 2008 through 2011 to date.
n) Please identify the amount and estimated date of pension funding payments for the remainder of 2011 and for 2012.
o) Please identify the amount and estimated date of OPEB funding payments for the remainder of 2011 and for 2012.

Response:

a) No. The information provided in *Pre-Filed* 1.23 covered actual valuations for 2008, 2009 and 2010. The information contained in JCL_WP35 was based upon projected 2011 valuation, provided in (b).

b) The 2011 and 2012 pension and OPEB costs were developed using the modeling tool provided by Towers Watson and actual inputs for trust fund balances, returns, etc. See attachment, APS14989, which contains the model inputs and outputs.

c) The "SEBRP" is the Supplemental Executive Benefit Retirement Plan (i.e. unqualified pension plan).

d) Yes, they are the same.

e) None of the $26,219,162 on JCL_WP35 relates to the Supplemental Executive Benefits Retirement Plan.

f) No. Costs associated with Supplemental Executive Benefits Retirement Plan have not been deferred by the Company.

g) The $23,948,768 on JCL_WP35 ties to the $23.949 million in Section 9.3 of the Settlement Agreement. This amount only includes $17,228,847 for pension and $6,719,921 for OPEB. It does not include SERBP or "Misc Items."

h) No. It does not include any "Misc Items" as Section 9.3 of the Settlement Agreement only allows APS to defer costs associated with Pension and OPEB.

Witness: Jay La Benz

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Response to Staff 27.1 Continued:

i) See attachment APS14990, which contains the latest (2011) valuation, presented to the Company on May 20, 2011 by Towers Watson. Please note these are total plan expenses and include not only those amounts related to APS O&M, but APS capital, and those billed to other participant owners of joint facilities that the Company operates but does not own 100% the assets. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

j) Yes. See attachment APS14991, which contains the 2012 Budget, which is based on APS's most recent Pension and OPEB assumptions. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

k) The numbers for 2011 and 2012 are identical because an estimate for 2012 costs was not available and the Company had no additional information at the time of filing that would warrant assuming a difference. Please see response to part (j) for the most recent 2012 assumptions.

l) Pension – 2011 – $0 to date
Pension - 2010 - $194,880,000 (January - $48,365,000, March - $48,365,000, December - $98,150,000).
Pension 2009 - $0
Pension 2008 - $33,705,000 September

m) OPEB – 2011 - $0 to date
OPEB – 2010 - $16,391,050 December
OPEB – 2009 - $14,998,778 December
OPEB – 2008 - $10,569,301 (September - $9,702,601, December - $866,700)

n) 2011 - $0
2012 - $67,041,000

o) 2011 - $19,718,000
2012 - $19,718,000

PAGES 12-16 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

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OCTOBER 6, 2011

Staff 19.21: Grants and government awards. Refer to the response to STF 15.23. Refer to APS14788, pages 2 and 6 of 12.

a) Have grant monies related to any of the three items listed on APS14788, pages 2 and 6 of 12, been received by APS (1) as of December 31, 2010, or (2) currently? If not, explain fully why not. If so, please identify the amounts of grant money received for each listed item at each date, and show in detail how APS has accounted for those funds.

b) Please identify the amount of test year expense, by account, for Lewis & Fowler consultants.

c) Please identify the amount of test year expense, by account, for each of the following (per APS14788, page 8 of 12):

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Response: a) The Grants referred to in the table below are: Integrated Energy System with Beneficial CO2 Use (IES); the High Penetration of Photovoltaic Generation Study – Flagstaff Community Power (HPS), and the Distributed Energy Leadership (Utilities) Program (DELP).

Grant Name	Account	As of December 31, 2010	Year-to-date September 30, 2011
IES	1430	$ 380,162.82	$ 0.00
HPS	1430	$ 314,387.95	$ 281,632.83
DELP	1430	$ 62,113.51	$1,953,065.90

For information related to IES, please see APS response to Staff 9.2.

b) Please see below table:

Vendor	Account	2010
Lewis & Fowler	9200	$ 339,925.48

Witness: Jeff Guldner

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Response to Staff 19.21 Continued:

Lewis & Fowler provided government grant compliance and oversight work associated with all of APS' government-funded grants and certain types of third party contracts funded with government monies.

Lewis & Fowler had a separate work scope supporting IES that cost for which is not reflected in the table above and for which APS has proposed to remove from the Test Year. Please see APS's response to Staff 9.2.

(c) [redacted] Please note this portion of the response is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jeff Guldner

PAGES 19-21 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

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OCTOBER 12, 2011

Staff 21.2: General Advertising Expense. Refer to the response to Prefiled 1.40, APS14082. Please provide the contract for the External Advertising Retainer, $480,000.

Response: Attached as APS14914 is the requested contract. Please note the attachment is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jay La Benz

ARIZONA CORPORATION COMMISSION
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OCTOBER 14, 2011

Staff 22.2: Annual Incentive Compensation. Refer to the response to STF 1.34, APS14222.

a) Please provide similar information showing the annual incentive compensation expense, by account, for each year 2008 and 2009.

b) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to officers and senior management.

c) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to union employees.

d) Please identify how much of the annual incentive compensation in each year, 2008, 2009 and 2010 relates to front line and non-senior management.

e) Please provide the ACC jurisdictional amounts, by account, for the annual incentive compensation expense for each year 2008, 2009 and 2010.

Response: (a)-(e) See attachment APS14921 for 2008, 2009 and 2010 requested information. Please note this attachment is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jay La Benz

PAGE 24 IS CONFIDENTIAL AND HAS BEEN REDACTED

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Staff 20.8: Annual incentive plan (AIP).

a. Please identify the amount of AIP cost, by account, APS has requested be included in the Company's proposed pro forma adjusted operating expenses.

b. Please identify the amount of AIP cost, by account, APS recorded in 2010.

c. Please reconcile the amount identified in response to part b) with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** mentioned on APS14820, page 3 of 9.

d. Please provide the high-level documentation for the annual incentive plan calculation process, mentioned on APS14820, page 4 of 9, in item 3.

e. Please provide the documentation related to the 2010 incentive calculation process, mentioned on APS14820, page 4 of 9, in item 2.

f. Please identify the earnings requirement and threshold earnings that must be achieved prior to any payout under the AIP (referenced on APS14820, page 6 of 9) and provide the documentation related to measuring it and evaluating whether it was achieved. Provide this information for the 2010 AIP payout, and also, provide the earnings requirement and threshold earnings that must be achieved prior to any payout under the AIP for 2011.

g. Provide the documentation for the Individual Performance component that was added in 2010, per APS14820, page 6 of 9.

h. How did APS account for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** mentioned on APS14820, page 7 of 9. Show the amounts by account recorded for this in each year, 2010 and 2011.

i. Has APS included any amount in its expense request related to the $220,000 mentioned on APS14820, page 7 of 9? If so, please identify the amount by account.

Witness: Jim Hatfield/Jay La Benz

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j. APS14820, page 8 of 9 mentions **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

   1. Please provide a copy of the corrected spreadsheet in Excel. If a corrected Excel spreadsheet does not exist, provide in Excel the original spreadsheet that was used for the calculations of AIP noted on APS14820, page 8 of 9.

   2. Please identify the Officer amounts of AIP incentive compensation for 2010 by account.

k. Please reconcile the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

l. Refer to APS14820, page 9 of 9. Please provide the formalized documentation of the incentive calculation, including the documentation of the Company and Business Unit incentive metrics for each of the business unit areas. Please provide this information for 2010 and 2011. Please identify any related Excel files showing AIP calculations for each year, and provide such Excel files electronically in Excel.

Response:

a) See attachment APS14893 for the cost by account that APS has requested in this case.

b) See same attachment as provided in a).

c) [redacted]

d) The high-level management action plan documentation is scheduled to be completed by October 31, 2011.

e) See response to d).

Witness: Jim Hatfield/Jay La Benz

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Response to Staff 20.8 Continued:

f) For the 2010 AIP, the plan documents were previously provided in response to Staff 1.16 and pre-filed 1.24. The actual APS earnings achievement of $336M is as shown on SFR E-9 and as provided in response to Staff 1.16. For the 2011 AIP, the plan documents were provided in Staff 1.16.

g) The Individual Performance component documentation is as described in the 2010 plan document, which was previously provided in Staff 1.16.

h) [redacted]

i) Yes, the $220,000 costs have been included as described in the response to h) and the attachment to a) above.

j) [redacted]

1) This was an error contained in a draft document, which was fixed before it was sent to the HR Committee. This corrected error was unrelated to the incentive cost accrual that was recorded in 2010 and included in the test year filing.

2) [redacted]

k) [redacted]

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OCTOBER 6, 2011

Response to Staff 20.8 Continued:	l) See response to d) above.
	Please note some portions of this response are confidential and are being provided pursuant to an executed protective agreement.

Witness: Jim Hatfield/Jay La Benz

STF 20.8 a), b), c), h), j2) & k)
Annual Incentive Plan Costs for 2010

	Total APS Annual Incentive Plan Costs for 2010 FERC Acct	Amount ($000)	Officer Portion Amount ($000)
Capital	107	9,188	
	Payroll Taxes	643	
		9,831	0
O&M	506	4,779	330
	519	784	
	524	7,052	352
	546	1,198	82
	549	566	
	557	963	69
	566	1,470	441
	588	6,662	
	903	3,242	146
	916	703	41
	920	2,814	1,211
	928	285	75
	930	1,008	798
	O&M Incetive Total	31,525	3,545
	Payroll Taxes	2,890	314
		34,415	3,859

	Total Incentive Plan Costs Amount ($000)	Officer Portion Amount ($000)
Participants	30,964	3,021
PNW/BTL	1,377	319
APS Capital	9,188	
APS O&M	31,525	3,545
Total	73,054	6,885

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-11-0224
JULY 14, 2011

Staff 1.16: Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2009-2011, and all evaluations of whether such goals were exceeded.

Response: As shown in response to Staff 1.15, the retirement programs consist of the SERP program, the 401-K program and the pension plan program. Please see that response for details of the retirement programs. The incentive program for APS is the APS Annual Incentive Award program. APS provided the plans for 2009 and 2010 in response to Pre-Filed 1.24. The 2011 APS Annual Incentive Plan is attached as APS14212. The performance and metric results for the 2008, 2009 and 2010 Annual Incentive Plans, as communicated to our employees, is attached as APS14213, APS14214 and APS14215. Please note that this information is confidential and is being provided pursuant to an executed protective agreement.

Witness: Jim Hatfield

PAGES 31-57 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

Arizona Public Service Company
Docket No. E-01345A-11-0224
Attachment RCS-5
Copies of Regulatory Commission Order Excerpts Addressing Sharing of Directors & Officers Liability Insurance Cost Between Shareholders and Ratepayers

Jurisdiction	Docket No.	Order Date	Utility	No. of Pages	Page No.
Florida	090079-EI; 090144-EI; 090145-EI	March 5, 2010	Progress Energy Florida, Inc.	4	2 - 5
Connecticut	08-07-04	February 4, 2009	United Illuminating Company	3	6 - 8
Connecticut	07-07-01	January 28, 2008	Connecticut Light and Power Company	3	9 - 11
Connecticut	05-06-04	January 27, 2006	United Illuminating Company	3	12 - 14
Connecticut	03-07-02	December 17, 2003	Connecticut Light and Power Company	3	15 - 17
Connecticut	98-1-02	February 5, 1999	Connecticut Light and Power Company	2	18 - 19
Connecticut	99-09-03	May 25, 2000	Connecticut Natural Gas Corporation	3	20 - 22
Arkansas	06-101-U	June 15, 2007	Entergy Arkansas, Inc.	3	23 - 25
Arkansas	04-121-U	September 19, 2005	Centerpoint Energy Resources Corp	3	26 - 28
Arkansas	04-176-U	October 31, 2005	Arkansas Western Gas Company	3	29 - 31
			Total Pages Including this Page	31	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

[40] Order No. *PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI,* In re: Petition for rate increase by Tampa Electric Company, p. 64.
[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

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[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-07-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

February 4, 2009

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Anthony J. Palermino

DECISION

TABLE P/R - 5

CORRECTED TABLE

(in $000s)

Compensation Expense	2009	2010
Proposed Base Payroll	$56,627	$59,115
Department Adjustment	($3,880)	($4,565)
Allowed Base Payroll	$52,747	$54,550
Overtime and Premium Pay	$6,754	$7,024
Department Adjustment	($1,672)	($1,942)
Allowed O/T and Premium Pay	$5,082	$5,082
Capitalized Overhead Pay	($4,083)	($4,207)
Department Adjustment	$80	$63
Allowed Cap. O/H	($4,003)	($4,144)
Incentive Compensation	$7,665	$7,791
Department Adjustment	($3,671)	($3,797)
Allowed Incent. Comp.	$3,994	$3,994
Total Compensation Proposed	**$66,963**	**$69,723**
Total Dept. Adjustments	**($9,143)**	**($10,241)**
Total Allowed Compensation	**$57,820**	**$59,482**
Allocated Incentive Comp.	**$1,154**	**$1,146**
Total Department Adjustments	**($553)**	**($559)**
Allowed Alloc. Inc. Comp.	**$601**	**$587**
Total Compensation Adjustments	**($9,696)**	**($10,800)**

To address the public's concern that customers are paying 100% of the compensation paid to the top officers of the Company, the Department offers that, for example, the adjustments made in this Decision reduce the amount of compensation paid to the Company President and Chief Operating Officer, that are actually included in rates and paid by customers, by approximately 33% and 31%, respectively.

2. Directors and Officers Liability Insurance

In its Application UI requested the Department authorize $844 thousand for 2009 and 2010 Directors and Officers Liability Insurance (DOL) ($852 thousand less $8 thousand allocated to non-regulated entities). Schedule WP C-3.31 A&B. The Company's position is that DOL is a business expense of having a public corporation, and the customers pay for all of the ordinary business expenses that a company would incur. Tr. 10/14/08, pp 62 and 63.

The OCC stated that in the past two rate decisions involving UI, the Department has determined that a portion of UI's DOL insurance costs should be funded by ratepayers. Despite this fact, UI is proposing to recover 100% of its DOL insurance costs in this proceeding. The OCC cited its previous arguments that corporate scandals have increased costs dramatically, that ratepayers do not elect the Board of Directors (BOD) and officers of the Company, and that shareholders, who are protected by the insurance, should not be subsidized by ratepayers for DOL insurance costs that are designed to protect shareholders from their own decisions. The facts and circumstances regarding the DOL insurance have not changed since UI's last rate case. The OCC recommends that the DOL insurance be reduced by 75% with only 25% being passed on to customers, but stated that its absolute preference would be to disallow the cost completely. OCC Brief, pp. 79 and 80.

The AG indicates that the amount requested is roughly six times the amount that the Department approved in the 2006 Decision. In the 2006 Decision, the Department specifically agreed with both the AG and OCC that "DOL insurance protects only shareholders from the actions of management that they selected." Although the Department allowed UI to collect one-quarter of its requested amount in the 2006 Decision, the Company requested the entire amount be funded by ratepayers. The AG stated that this bold act of indifference to the Department's clear precedent and to the financial stresses facing its customers should be firmly rejected. At the very most, the Department should authorize only the levels for DOL insurance that it approved in the 2006 Decision. AG Brief, p. 18.

In the 2006 Decision, the Department noted the OCC's and AG's positions, as well as the position of the Company who stated that if there was no insurance and there was a huge claim, it could put the Company in financial peril, which would potentially impair its ability to serve. Therefore, the Department allocated 75% of DOL costs to the shareholders, with the residual 25% to be funded by ratepayers. 2006 Decision, pp. 46 and 47. The Department rejects the Company's current proposal that ratepayers fund 100% of DOL insurance costs, and reconfirms the precedent afforded by the 2006 Decision. Accordingly, the Department allows $211 thousand of DOL insurance costs to be funded by ratepayers in years 2009 and 2010 ($844 thousand times 25%). This results in DOL insurance expense decreases of $633 thousand in each of years 2009 and 2010.

3. Fringe Benefits

a. Compensation Adjustment to Fringe Benefits

In Section III.1.f., the Department made adjustments to compensation of $12.033 million and $13.655 million in 2009 and 2010, respectively. This also results in an adjustment to fringe benefits that accompany compensation. The Company indicates that its composite fringe benefit rate for 2009 and 2010 is 45%. Responses to Interrogatories EL-30-2; EL-31-2; and EL 33-1.

In its Written Exceptions, the Company argues, against its own filed and sworn record evidence of a 45% fringe benefit expense related to compensation, that the "correct compensation-driven benefits loader from an expense standpoint" is 20.6% and attempts to justify that amount by listing greatly reduced expense amounts for certain "Compensation Driven Employee-Related Benefits Loader." UI Exceptions, pp. 29 and 30. The Department notes that the Company's Response to Interrogatory EL-33 that

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 07-07-01 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

January 28, 2008

By the following Commissioners:

Anthony J. Palermino
Anne C. George
John W. Betkoski, III

DECISION

expenses by $2.232 million to remove the non payroll projected costs in excess of the original budget.

2. Insurance Expense

The test year expense for insurance expense was $6.817 million. The Company proposed a rate year increase of $.65 million or a rate year expense of $7.467 million. Application, Schedule C-3.10. CL&P revised the request and reduced the insurance expense by $17,000. The revision was a result of recent premium information. The change is a combination of increases and decreases in different types of insurance. Response to Interrogatory EL-80-SP01.

The Department accepts the Company's revisions except for the Directors and Officers insurance expense and capital allocation as discussed in detail below.

a. Director and Officer Insurance Expense

The test year expense for Director and Officer (D&O) insurance expense was $1.423 million. The Company proposed a rate year increase of $0.164 million or a rate year expense of $1.587 million. Application, WP C-3.10. As indicated above, CL&P revised its rate year insurance expense and decreased the rate year D&O insurance expense amount by $.270 million to $1.317 million. Response to Interrogatory EL-80-SP01 and Late Filed Exhibit No. 112SP-01.

CL&P claims that D&O insurance is a legitimate and customary operating expense and that no director or officer with the necessary knowledge and experience would take the risks associated with serving CL&P without this type of protection. CL&P states that the Sarbanes-Oxley Act requires that certain skill-sets be reflected in the Board of Directors (BOD), and in order to attract and retain individuals that meet these requirements CL&P must offer D&O coverage to its BOD. CL&P indicated that the Department has already confirmed that D&O is a necessary operating expense that is recoverable. CL&P Brief, p. 39.

The AG argues for the removal of the entire $1.587 million. The AG states that it is inappropriate to force customers to fund a plan that benefits only shareholders. D&O insurance protects shareholders from their own decisions and is intended to protect directors and officers from lawsuits brought by shareholders. AG Brief, p. 20.

The OCC states that premiums for insurance excluding D&O insurance decreased from $9.4 million to $8.41 million while D&O insurance is estimated to increase 11.5% from $1.423 million to $1.587 million. Further, the OCC believes that the D&O insurance requested amount is excessive, ignores the Department's prior rulings, and ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. The OCC argues that Sarbanes-Oxley merely requires officers & directors who have a fiduciary duty to acknowledge responsibility by signing their names. It was not the implementation of Sarbanes-Oxley that caused an increase in premiums, it's the claims filed that caused the increase. The OCC adds that D&O insurance has drastically increased from 5.67% of the aggregate insurance amount in 2002 to 13.15% in 2006 and projected to cost 15.87% in the rate year. The OCC recommends a D&O insurance reduction of $1.202 million to $0.385 million. The OCC calculated this amount by using the 2002 test year amount increased by inflation. OCC Brief, p. 44.

In Docket No. 03-07-02, CL&P requested a rate year amount of $1.043 million and was allowed the test year amount of $.330 million. 03-07-02 Decision, pp. 48-49. This allowed 33% of the requested amount. In that decision, the Department indicated that it does allow some level of D&O insurance expense in rates to assure some level of ratepayer protection from lawsuits. In the UI Decision, the Department allowed 25% of the D&O insurance expense to be allocated to customers. In the Decision dated February 5, 1999, n Docket No. 98-01-02, DPUC Review of the Connecticut Light and Power Company's Rates and Charges – Phase II, the Department took the OCC approach and calculated the 1999 expense by inflating the 1996 level. This allowed 46.7% of the requested amount. In the Decision dated May 25, 2000, in Docket No. 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase, the Department allowed 20% of the premium amount.

The Department agrees in part with the OCC that ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. However, the Department historically has allocated a percentage to ratepayers to protect from catastrophic lawsuits. Accordingly, the Department finds it appropriate to allocate 30% to ratepayers and 70% to shareholders. This allocation is fair and consistent with the level allowed in Docket No. 03-07-02. Therefore, the Department allows $.395 million ($1.317 million x 30%) and disallows $.922 million to be collected in rates.

b. Insurance Expense - Capital Allocation

CL&P originally proposed a rate year capitalization factor of 25.3%. Application, Schedule WPC-3.10. The Company revised this amount to 26.6% in order to reflect updates based on recent invoices. Response to EL-80-SP01 and Late Filed Exhibit No. 112. The test year before pro forma adjustment was 35.6%. Application, Schedule WPC-3.10. A majority of the pro forma adjustment was to remove a non-recurring charge for the public liability reserve. This adjustment was based on an independent study performed by Mercer, Inc. The remaining pro forma adjustment included the addition of $284,000 that was for a non-recurring credit or refund received from USICO, a mutual property insurance company. Response to Interrogatory EL-43.

The OCC claims that CL&P has included a significant increase in the percent of costs being charged to expense as opposed to capital. Specifically, the Company's proposed reduction of more than 10% to the capital allocation is significant considering CL&P's focus on system improvements. The OCC argues that the Company did not present any evidence to justify an allocation change. OCC Brief, p. 41. The OCC recommends using the test year capitalization factor of 35.6%. That capitalized amount reduces the aggregate insurance expense to $5.802 million for a total disallowance of $1.665 million. OCC Brief, pp. 43-44.

As indicated below, the Company's insurance capitalization percents have ranged from a low of 25.6% to a high of 40.5% in the years 2002 through 2006.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

January 27, 2006

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg
Anne C. George
Anthony J. Palermino

DECISION

Description	2006	2007	2008	2009
Benchmarking studies	$ 72,000	$ 72,000	$ 73,000	$ 74,000
BPL	$ 98,000	$ 98,000	$ 98,000	$ 98,000
Regulatory consulting	$ 131,000	$ 138,000	$ 145,000	$ 152,000
Client services support	$ 275,000	$ 296,000	$ 311,000	$ 329,000
Total professional services expense disallowed	$ 576,000	$ 604,000	$ 627,000	$ 653,000

8. Outside Services - Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A–D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

9. Directors and Officers Liability Insurance

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/12/05, p. 868. Further, the Company asserts that, taken to the extreme, "if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve." Tr. 10/11/05, p. 801.

The OCC indicates that "the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket." Schultz and DeRonne PFT, p. 48. Further, "DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions." OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A – D.

The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. See http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

The Department, therefore, accepts the Company's revision to computer and other expenses as indicated in the Response to Interrogatory OCC-93. Accordingly, the Department reduces computer expenses by $.348 million ($10.119 million less $9.771 million) and other O&M expenses related to the test year processing and storage balance of $.596 million, for a total O&M adjustment for these items of $.944 million ($.348 million plus $.596 million).

2. Insurance Expense

a. Directors and Officers Liability Insurance

The Company requested Directors & Officers Liability Insurance Expense (D&O Insurance) of $1.043 million in the rate year. This included a test year pro forma adjustment of $.029 million and a rate year adjustment of $.684 million above the test year actual amount of $.330 million based on the actual renewal premiums for the policy period 4/23/03 to 4/23/04. Schedule WP C-3.12; Response to Interrogatory OCC-101.

The OCC argues for the removal of the entire $1.043 million of D&O Insurance expense. The OCC states:

> Ratepayers should not be forced to pay a cost that protects shareholders from the shareholders' own decisions. Shareholders determine who the Board of Directors are and the Board of Directors are responsible for appointing officers of the Company. The officers are highly compensated to provide quality leadership with the utmost integrity. Ratepayers are responsible for paying for the directors and officers services. The shareholders, not ratepayers, determine who the directors and officers are. Therefore, the shareholder should assume the risk associated with their decision regarding the management of the Company. The cost to obtain insurance to protect the shareholders investment from their choice of management should be the responsibility of the shareholders.

OCC Brief, p. 64

The OCC also cites that the escalation in D&O Insurance rates stem from the insurers' need to continue to reserve for litigation and settlement expenses in connection with an influx of claims arising from such entities as Worldcom, Enron, Kmart, etc. Response to Interrogatory OCC-101. The increases in D&O Insurance and the related costs are due to the failures of directors and officers to ensure the Company operated prudently and reasonably. An alternative to total disallowance of cost would be to allow the test year cost of $.330 million. OCC Brief, p. 65.

The Department is sympathetic with OCC's arguments and generally agrees that the increased premiums are, at least in part, caused by Officer/Director mismanagement or misconduct in major corporations. Further, the Department notes that CL&P's recent claims experience includes settlement of eight federal and state shareholder class action lawsuits that stemmed from the Nuclear Regulatory Commission's Watch List of problems at its Millstone Nuclear Plant in 1996 that resulted in a $20.050 million settlement by its insurer. Further, a $33 million settlement was reached with the non-NU joint owners of Millstone 3 related to the Company's operation of that plant. Late Filed Exhibit 73 and 73-SP01. However, the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits. Therefore, the Department will allow the test year cost of $.330 million and reduce the Company's D&O Insurance expense by $.713 million ($1.043 million less $.330 million).

b. Public Liability Expense

The Company requested Public Liability Expense of $2.591 million in the rate year in Account 925.02. This Account includes the cost of the reserve accrual to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. It also includes the cost of labor and related supplies and expenses incurred in injuries and damages activities. Uniform System of Accounts prescribed for Electric Utilities, Public Utilities Control Authority State of Connecticut, 1/1/63, p. 177 (USOC). In its calculation of this expense, CL&P removed $1.497 million of test year expense that was capitalized, thus reducing the overall test year expense of $2.591 million to $1.094 million. Schedule WP C-3.12.

In response to an OCC data request, the OCC questioned why CL&P should no longer treat the public liability expense as an overhead cost, subject to capitalization. In the Company's response it indicated "[u]pon further review it was determined that public liability insurance is an appropriate cost to be capitalized under the FERC Electric Plant instructions." CL&P determined that the payroll overhead rate is the best vehicle for capitalizing these costs and changed the overhead rate for the remainder of 2003 to include these costs. Response to Interrogatory OCC-99. Accordingly, the OCC recommends that $1.497 million of public liability expense be capitalized, thereby reducing CL&P's proposed expense.

The Department agrees with the OCC and the Company that a portion of public liability expense, particularly as it relates to construction projects, is properly capitalizable. The USOC provides, for example, that the cost of injuries and damages or reserve accruals capitalized shall be charged to construction directly or by transfer to construction work orders from this account. USOC, p. 177. The Department also notes that it has been CL&P's consistent practice to capitalize a portion of public liability expense. Response to Interrogatory OCC-100. The Company provided a revised schedule that calculated the capitalized portion of Public Liability Expense using a capitalization rate of 38.5% that resulted in a capitalization amount of $.998 million. Schedule WP C-3.12 Revised. The Department notes that the capitalization percentage is consistent with other payroll-related capitalizations. Schedule WP C-3.28a. The Department, therefore, reduces public liability expense by $.998 million to reflect such capitalization.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold
Donald W. Downes
John W. Betkoski, III

DECISION

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-09-03 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

May 25, 2000

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold

DECISION

tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 x 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 x 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] x 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. Insurance

a. Directors and Officers Liability

CNG has included the cost of D&O liability policies in pro forma insurance expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The

Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% x $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear. Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ENTERGY ARKANSAS, INC. FOR APPROVAL OF CHANGES IN RATES FOR RETAIL ELECTRIC SERVICE	))))	DOCKET NO. 06-101-U ORDER NO. 10

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

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[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, *lobbying, and donations, including support and sponsorship* of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

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ARKANSAS PUBLIC SERVICE COMMISSION

FILED

IN THE MATTER OF AN APPLICATION FOR A GENERAL CHANGE OR MODIFICATION IN CENTERPOINT ENERGY ARKLA, A DIVISION OF CENTERPOINT ENERGY RESOURCES CORP'S RATES, CHARGES, AND TARIFFS	)	DOCKET NO. 04-121-U ORDER NO. 16

ORDER

On November 24, 2004, CenterPoint Energy Arkla ("Arkla" or the "Company") filed an Application for approval of a general change or modification in its rates and tariffs.[1] Arkla's initial Application reflects that it was seeking a non-gas rate increase of $33,996,382 based on an overall non-gas revenue requirement of $182,525,265. Order No. 4, entered on December 16, 2004, suspended Arkla's proposed rates, charges, and tariffs pending further investigation by the Commission.

The parties to this proceeding are Arkla, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Arkansas Gas Consumers ("AGC"), and the Commercial Energy Users Group ("CEUG").

Arkla filed the written testimonies of Jeffrey A. Bish, Charles J. Harder, F. Jay Cummings, Samuel C. Hadaway, Alan D. Henry, Michael TheBerge, Gerald W. Tucker, Steve Malkey, Michael J. Adams, Walter L. Fitzgerald, Michael Hamilton, and John J. Spanos. The Staff filed the written testimonies of Robert Booth, Alice D. Wright, Alisa Williams[2], Don E. Martin, Gail P. Fritchman, Don Malone, L.A. Richmond, Gayle Frier, Johnny Brown, Robert H. Swaim, and Adrienne R.W. Bradley. The AG filed the written testimony of William B. Marcus.

[1] Arkla filed additional revisions to its Application on December 27, 2004, January 10, 2005, and January 13, 2005.
[2] On August 3, 2005, the Staff filed Notice that Jeff Hilton, Manager of Staff's Audit Section, was adopting the pre-filed testimony of Staff witness Alisa Williams.

adjustments were calculated by applying the contribution rate to each party's respective payroll adjustments.

The Commission finds that the employee savings plan contribution rate should be applied to the amount determined for regular salaries and wages, overtime, and incentive pay consistent with the Commission's decision on these issues. The Commission accepted Arkla's position on regular salaries and wages, and overtime, and the Staff's position on incentive pay. (Adjustment No. IS-20).

Director's and Officer's Insurance ("D&O")

The purpose of D&O insurance is to protect officers and directors of a corporation from liability in the event of a claim or lawsuit against them asserting wrongdoing in connection with the Company's business. AG witness Marcus has two concerns with Arkla's treatment of this expense: (1) Arkla's revised allocation methodology from an asset-based to an O&M-based allocation has doubled Arkla's costs; and (2) the costs should be split on a 50-50 basis to recognize that shareholders are the major beneficiaries of policy payouts when something goes wrong. (T. 1376-1377) Arkla Witness Harder testified that the use of an O&M allocation factor is appropriate for an expense that bears no relation to the level of plant. He contended that this is a necessary business expense which enables the Company to attract and retain qualified management. (T. 152-153) Mr. Marcus disagreed, stating that the expense is not related to O&M expense either, the allocation shifts the cost to Arkla away from Arkla's electric affiliate, and utility profits are asset-based. Also, since shareholders receive the benefit of insurance payouts, they should bear a portion of the cost of buying the insurance. (T. 1465-1466) Mr.

Harder responded, contending that: (1) the AG cites no evidence to show shareholders are the primary beneficiaries of these insurance proceeds; (2) litigation often involves past stockholders, in which instance they are no different than other individuals filing tort claims; and (3) when current shareholders are involved, payments are made to the corporation in which case customers are the ultimate beneficiaries. (T. 1227-1229)

The Commission finds that Arkla has not justified its change in allocation factors nor has it justified why this expense should not be split equally between stockholders and ratepayers. Arkla did not adequately explain why, at this time, it changed from a asset-based to an O&M expense-based allocation factor. Arkla's explanation that it is an expense to attract qualified management does not establish a justifiable relationship between the cost and the cost expense allocation factor the Company used. Mr. Marcus testified that D&O insurance costs are part of general corporate overhead to protect Company profits which are largely asset-based for a utility. (T. 167-169) Mr. Marcus' testimony that this insurance protects corporate profits also lends support for sharing the insurance costs between shareholders and ratepayers. The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayes.

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ARKANSAS PUBLIC SERVICE COMMISSION OCT 31 2 45 PM '05

FILED

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS)

DOCKET NO. 04-176-U
ORDER NO. 6

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

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3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
S-3

GARY PIERCE
Chairman
BOB STUMP
Commissioner
BRENDA BURNS
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

DAVID C. PARCELL
EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

My Direct Testimony provides my estimate of the cost of capital for Arizona Public Service Company ("APS" or "Company"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	46.06%	6.38%	2.94%
Common Equity	53.94%	9.90%	5.34%
Total Capital	100.00%		8.28%

The only difference between my 8.28 percent recommendation and the 8.87 percent cost of capital request of APS is the cost of common equity – **I propose a cost of equity of 9.9 percent** and APS requests a cost of equity of 11.0 percent.

My 9.9 percent cost of common equity is derived from my consideration of three costs of equity models:

Discounted Flow	9.3-10.5%
Capital Asset Pricing Model	7.0-7.2%
Comparable Earnings	9.5-10.0%

However, my recommendation for APS focuses on the results of the Discounted Flow and Comparable Earnings Analyses.

In addition, my Direct Testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of APS. I recommend two alternative FVROR values for APS – a 5.74 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 6.05 percent value using a 1.00 percent inflation-adjusted risk-free return.

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EXHIBITS

ATTACHMENTS

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 580, 9030 Stony Point Parkway, Richmond, Virginia 23235.

Q. Please briefly describe your background and experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. In connection with this, I have previously filed cost of capital testimony in about 470 public utility ratemaking proceedings before some 50 regulatory agencies in the United States and Canada. I have previously testified in approximately 20 public utility rate proceedings before this Commission, including the two prior rate cases of Arizona Public Service Company ("APS" or "Company"). Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Utilities Division Staff ("Staff") to evaluate the cost of capital aspects of the current filing of APS. I have performed independent studies and am making recommendations on the current cost of capital for APS. In addition, since APS is a subsidiary of Pinnacle West Capital Corporation ("PWC" or "Parent"), I have also evaluated PWC in my analyses.

Q. Have you prepared schedules in support of your testimony?

A. Yes, I have prepared one exhibit, labeled Schedule 1 through Schedule 13, attached to my testimony. These schedules were prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendation for APS is shown on Schedule 1 and can be summarized as follows:

	Percent	Cost	Return
Long-Term Debt	46.06%	6.38%	2.94%
Common Equity	53.94%	9.3-10.5%	5.02-5.66%
Total	100.00%		7.95-8.60%
			8.28% with 9.9% ROE

Q. Please summarize your analyses and conclusions.

A. This proceeding is concerned with APS's regulated electric utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. I have used the December 31, 2010 capital structure of APS, as proposed in the Company's filing, in my analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of long-term debt. I have used the cost rate for long-term debt proposed by APS.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for

APS. Each of these methodologies is applied to a group of proxy utilities similar to APS/PWC and the group of electric utilities used by APS witness William E. Avera. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow (DCF)	9.3-10.5% (9.90% mid-point)
Capital Asset Pricing Model (CAPM)	7.0-7.2% (7.10% mid-point)
Comparable Earnings (CE)	9.5-10.0% (9.75% mid-point)

My recommendation for APS focuses on the results of the DCF and CE analyses. I have focused on both the broad range (i.e., 9.3 percent to 10.5 percent) and the mid-points of these analyses (i.e., 9.90 percent for DCF and 9.75 percent for CE). My recommendation is a range of 9.3 percent to 10.5 percent, or a **9.90 percent mid-point estimate**. This 9.90 percent recommendation also properly reflects the tough economic times that both the U.S. and APS's service areas have and are enduring.

Combining these three steps into weighted cost of capital results in an overall rate of return of 7.95 percent to 8.60 percent, with a mid-point estimate of 8.28 percent (which incorporates a cost of common equity of 9.90 percent).

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. Thus, the revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an <u>ex post</u> (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an <u>ex ante</u> (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Two United States Supreme Court decisions provide guidance for determining a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> *What annual rate will constitute* ***just compensation*** *depends upon many circumstances and must be* ***determined by the exercise of fair and enlightened judgment****, having regard to all relevant facts. A* ***public utility*** *is entitled to such rates as will permit it to* ***earn a return*** *on the value of the property which it employs for the convenience of the public equal to that* ***generally being made*** *at the same time and in the same general part of the country on* ***investments in other business undertakings*** *which are* ***attended by corresponding risks and uncertainties****; but it has no* ***constitutional right to profits*** *such as are realized or anticipated in* ***highly profitable enterprises or speculative ventures****. The* ***return*** *should be reasonably sufficient to assure confidence in the* ***financial soundness*** *of the utility, and should be adequate,* ***under efficient and economical management****, to maintain and* ***support its credit*** *and* ***enable it to raise the money*** *necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.* **[Emphasis added.]**

Thus, the Bluefield decision, in my opinion as a non-lawyer, established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> *The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a* ***balancing*** *of the* ***investor*** *and* ***consumer interests*** *. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt*

> *and dividends on the stock. By that standard the* ***return*** *to the equity* ***owner*** *should be* ***commensurate*** *with* ***returns*** *on* ***investments*** *in* ***other enterprises having corresponding risks****. That return, moreover, should be sufficient to assure confidence in the* ***financial integrity*** *of the enterprise, so as to* ***maintain its credit*** *and to* ***attract capital****.* **[Emphasis added.]**

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests; namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> *"In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that Congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."*

[1] 294 P.2d 378 (1956).

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of APS property, which it is required to consider under Article 15, Section 14 of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that APS witness Avera also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company. *See* Avera Direct at page 8.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility. Many state regulatory commissions rely upon the DCF and CAPM models to develop the cost of common equity for utilities.

Q. What methods did you use to determine APS' cost of common equity?

A. I utilized three methodologies to determine APS's cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the cost of capital for APS?

A. Yes. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital:

- the level of economic activity (*i.e.,* growth rate of the economy);
- the stage of the business cycle *(i.e.,* recession, expansion, or transition);
- the level of inflation; and
- expected economic conditions.

My understanding is that this position is consistent with the Bluefield decision that noted "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." Bluefield, 262 U.S. at 679.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examine several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences, and thus permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the four prior business cycles and the most recent cycle.

A. The four prior complete cycles and most recent cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic, Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. As I will describe below, until the end of 2007, the United States economy had enjoyed general prosperity and stability since the early 1980s. This period had been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of venerable institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national entities such as Circuit City, and the bankruptcies of automotive manufacturers such as Chrysler and General Motors.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." The U.S. and other governments have implemented and continue to implement unprecedented actions to attempt to correct or minimize its scope and effects.

It appears that the recession reached its low point in mid-2009 and that the economy has since begun to expand again, although at a slow and sporadic rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time. As an example of this, the U.S. and Arizona unemployment rates still stand at about 9 percent – near the highest rates in decades.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of relevant economic data for the cited time period. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that 2007 was the sixth year of an economic expansion but, as I previously noted, the economy subsequently entered a significant decline, as indicated by the growth in real (*i.e.,* adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession was significant for both its depth and length of time it lasted.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially beginning in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008, the 2.7 percent level in 2009 and the 1.5 percent rate in 2010 were among the lowest levels of the past 30 years. This is indicative of virtually no inflation, which is reflective of lower capital costs.

Q. What have been the trends in interest rates over the four prior business cycles and the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates during the remainder of the

1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their then-lowest levels since the 1960s.

Since the recession began, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on several occasions; currently it is 0.25 percent, an all-time low. In 2008, there was a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, accompanied by an increase in corporate bond yields and a decrease in stock prices, reflecting the "flight to safety," wherein there was a reluctance of investors to purchase common stocks and corporate bonds while concomitantly moving their money into very safe government bonds. Since then, as seen on page 4, bond yields (both U.S. and utility) have declined to their lowest levels in the past four business cycles and in more than 35 years, with lending rates remaining at historically low levels.

Q. What trends does Schedule 2 show for common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that share prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously. Stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crises. Beginning in the second quarter of 2009, prices have recovered substantially but remain below the levels prevailing prior to the current recession. Through the third quarter of 2011, it is evident that stock prices maintain much of the volatility that was present during the recent financial crisis. I also note that events of the past four years have made public utility stocks, with their consistent and rising dividend rates, relatively more attractive to investors.[2]

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. It is apparent that recent economic and financial circumstances have been radically different from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and the increase in corporate bond yields are evidenced in the recent "flight to safety." On the other side of this "flight to safety" is the negative perception of the recent decline, which has significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns, including stock returns. Finally, as noted above, interest rates currently are at levels below those prevailing prior to the financial crisis of late 2008-early 2009 and are near the lowest level in the past 35 years. This "flight to safety" does not represent an increase in the cost of capital; rather, it more properly reflects an "availability of capital" since investors were unwilling to invest in many assets other than U.S. Treasury bonds. Further reflecting a decreased cost of capital, utility bond rates are at their lowest levels in the past four business cycles.

V. APS' OPERATIONS AND BUSINESS RISKS

Q. Please summarize APS and its operations.

A. APS is a public utility that generates, transmits, and distributes electric energy in Arizona. Its service area includes about 1.1 million customers in 11 of Arizona's 15 counties. APS

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[2] See, for example, Investment Insights, On Wall Street, "S&P Looks to Utilities ETFs in the Downtrodden Equities Market," August 22, 2011, http://www.onwall street.com/news/utility-stocks-etfs-investments-products-2679728-1.html.

also provides wholesale power to certain municipalities and other utilities. It is the largest utility in Arizona. APS is a subsidiary of Pinnacle West Capital Corporation ("PWC").

Q. Please describe PWC.

A. PWC is a holding company. Its principal subsidiary is APS.

Q. What has been the trend in APS's bond ratings in recent years?

A. This is shown on Schedule 3. APS's debt is currently rated Baa2 by Moody's and BBB by Standard & Poor's. As is indicated in Schedule 3, APS has higher Moody's ratings than its parent PWC. APS's debt has been rated in the Baa category (per Moody's) and BBB category (per Standard & Poor's) since at least 2000. It was downgraded by S&P to BBB- from BBB in 2005 and remained there until 2011, when it again obtained a BBB rating. It has had a Baa2 rating by Moody's since 2006.

Q. How do the bond ratings of APS compare to other electric and combination gas/electric utilities?

A. As I indicated in the previous answer, APS has Triple B bond ratings on its long-term debt. Below is a table depicting the bond rating data of the 59 electric utilities and combination gas/electric utilities covered by AUS Utility Reports:

Moody's Rating	Number of Companies	S&P Rating	Number of Companies
Aa3	2	AA-	2
A1	5	A+	1
A2	9	A	9
A3	14	A-	14
Baa1	11	BBB+	12
Baa2*	12	BBB*	7
Baa3	--	BBB-	6
Ba or less	--	BB	--
NR	4	NR	7

* APS ratings.

As this indicates, APS's ratings are generally lower than many utilities. However, the Company's ratings are higher than was the case prior to 2011, when APS's S&P ratings were at the bottom of investment grade.

Q. How does the current financial status of APS compare to that in existence at the time of the Company's last general rate proceeding in 2008?

A. As I indicated previously, APS had Baa2 security ratings by Moody's and BBB- by S&P in 2008, the time-frame of the Company's last general rate proceeding (Docket No. E-01345A-08-0172). The latter is the lowest investment grade category. This was emphasized by APS in its testimony in that proceeding. For example, APS President Brandt made the following points in his direct testimony in that proceeding:

> APS (was) in serious financial jeopardy (page 23, line 21);
>
> APS' declining ROE had caused Pinnacle West's stock to perform significantly worse than that of other electric utilities (page 27, lines 1-2);
>
> APS' credit ratings on its outstanding debt were currently on the lowest rungs of the investment grade credit ladder (page 31, lines 22-23);
>
> Each of the nationally recognized statistical rating organizations that rated APS' debt – S&P, Moody's, and Fitch – as well as various financial analysts had

recently noted the significant danger to downgrade presently threatening APS (page 32, lines 24-26 and page 33, line 1);

APS faced a "challenging regulatory environment" (page 33, line 2); and,

Growth was contributing to APS' financial pressure (page 42).

The BBB- credit rating by S&P, in fact, served as a focal point of APS' filing. Mr. Brandt devoted considerable testimony to the "adverse consequences of APS having its credit rating downgraded to junk." He cited the following "problems that come with non-investment grade credit ratings":

APS' access to the debt and equity markets would become limited to those lenders and investors (if any) willing to take the risk on a junk grade company (page 35, lines 23-25);

Investors will demand a higher yield for an investment in a company with low credit ratings to compensate for increased risk (page 36, lines 1-11);

APS would lose much of cost savings associated with outstanding tax-exempt debt (page 36, lines 12-20);

APS' access to commercial paper would be eliminated (page 36, lines 21-26 and page 37, lines 1-15);

APS may also lose many of its important existing bank credit agreements (page 37, lines 16-21); and,

Complications of APS' purchased power contracts (page 37, lines 22-26 and page 38, lines 1-9).

The potential of downgrades to below-investment grade status also was the focal point of APS' presentation in its interim rate case (Docket No. E-01345A-08-0172). This was demonstrated by the Opening Statement of APS' counsel in the 2008 interim rate hearing (September 15, 2008 Tr., page 9):

> Thus, what is really at issue in this proceeding is the objective evidence that APS once again faces a financial crisis because current rates, particularly after the expiration of the PSA surcharge in July of this year, do not provide APS with sufficient cash flow to fund its substantial capital expenditure obligations to meet system growth. And at the same time those existing rates undermine the ability of the company to earn the reasonable return on equity to which it is entitled.
>
> This twofold shortfall in earnings and available cash flow once again put the company's credit standing in jeopardy, a credit standing, by the way, as I am sure you all know and remember, that is already on the brink of junk status due to previous cash flow problems. And these problems that I have just described, as you will hear in this proceeding, have at the same time reduced the stock of Pinnacle West, APS's parent company, to essentially the lowest performing stock of all investor owned electric utilities in this country.

Since 2008, the financial condition of APS has improved substantially. As indicated above, S&P upgraded APS' debt to BBB in 2011. In addition, S&P assigns an outlook of "positive" to APS, indicating a further upgrade is more likely than a downgrade.

The stock rankings of PWC have also improved since 2008. For example, Value Line recently (mid-2011) raised PWC's "safety" from 3 to 2 and its "technical" rank from 3 to 2.

In addition, the regulatory climate of APS as viewed by the rating agencies has improved. The settlement among the parties in the 2008 general rate proceeding was viewed as constructive and positive. This also reflects a significant improvement in comparison to 2008 from the perspective of APS.

Finally, the stock price of PWC has performed favorably to that of the Dow Jones Utilities and the S&P 500 index from the beginning of 2010 (approximate implementation of rates from 2008 case) to the current time:

Pinnacle West Capital	24%
Dow Jones Utilities	16%
S&P 500 Index	14%

Q. Was the market-to-book ratio of APS an issue in the 2008 proceeding?

A. Yes, it was. In the 2008 interim rate hearing, APS witness Brandt stated (September 15, 2008 Tr. 66 and 68):

> . . . we are selling below book value in an extremely depressed market. We are one of the poorest performing electric utility stocks, virtually at the bottom of the universe of electric utility stocks.
>
> . . .
>
> Below book value you are basically confiscating the existing value of your shareholders. And you can get away with that maybe once, but these are the people . . . these are the long-term investors in the utility industry, long-term holders of our stock with obviously major positions, the top things, they don't forget things like this. And when you need it in the future, they will remember if you did do it in this environment.

Since that time, PWC's stock price has recovered to well above book-value. In fact, PWC sold common stock in 2010 at a price of $38.00 per share (net proceeds of $36.67 per share), well above the 2009 book-value of $32.69 (per Value Line).

Q. How do the rating agency descriptions of APS differ now in comparison to those in 2008?

A. There has been a substantial improvement in the rating agency descriptions of APS. This can be demonstrated by reviewing the language of S&P (the rating agency focused on by APS in the last general rate proceeding). For example, in a June 25, 2008 (i.e., at about the time of the 2008 rate filing) RatingsDirect on APS (Attachment 2), S&P cited the following "weaknesses:"

> Heavy construction program, coupled with a lagged regulatory process in Arizona;
>
> Continued tension in the relationship between APS and ACC, which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
>
> Consolidated free operating cash flows are expected to be negative through at least 2010; and,
>
> SunCor's near-term prospects to make distributions to its parent are limited.

In contrast, in the June 24, 2011 RatingsDirect (Attachment 3) wherein it raised APS' ratings, S&P noted the following:

> The ratings reflect our view of improved consolidated financial performance, evidenced by stronger credit metrics, and progress in advancing the regulatory strategy of APS in Arizona. A reduction in debt leverage from equity issuances and debt reductions, coupled with stronger cash flows from higher earnings and tax benefits, increased FFO to debt. Prudent financial management during the current rate case stay-out period and the use of cost riders resulted in improved financial stability. A shift in company focus toward improving regulatory relationships in the past few years continues to benefit credit quality because the company has transitioned to slower customer growth. We could raise the ratings further if regulatory dealings remain constructive and the company continues to manage the balance sheet with equity issuances to offset high capital spending.
>
> . . .

> The company has undergone a significant transition in recent years. High customer growth had necessitated that the company file regular general rate cases with the Arizona Corporation Commission (ACC) to recover its investments and operating costs, prior to the collapse of the housing market. The use of a historical test year in Arizona, coupled with an 18- to 24-month completion time for fully litigated rate cases, made it very difficult for APS to earn authorized returns. In recent years, regulatory lag has decreased and financial performance has improved because of interim rates, recovery of certain post-test-year costs, and an improved 11% authorized equity return in the previous general rate case. Slower growth and the addition of several rate case riders that allow the company to true up certain costs outside of the general rate case process have mitigated the need to file large cases frequently. However, capital spending remains due to replacements and renewable spending, necessitating a continued reliance on rate increases.

Q. Why are you describing APS' financial circumstances in 2008?

A. I am doing so to demonstrate that the 11.0 percent cost of common equity in the settlement in Docket No. E-01345A-08-0172 was a stipulated number that took into account, for example, the 9.0 percent low-end of the 9.0 percent to 11.0 percent range recommended in Staff's testimony, as well as all other aspects of settlement.

Q. Are you aware that APS is requesting the approval of several regulatory mechanisms in this proceeding?

A. Yes, I am. APS is requesting approval of the following new regulatory mechanisms in this case:

> Efficiency and Infrastructure Account (EIA) – revenue decoupling mechanism, which is annually adjusted based on a revenue per customer calculation; and,

> Environmental and Reliability Account (ERA) – allows APS to recover costs for environmental and generation capacity additions.

Q. In addition to these, has APS had access to any other regulatory mechanisms since its last general rate proceeding?

A. Yes, it has. APS has had the following regulatory mechanisms:[3]

- Power Supply Adjustor ("PSA") – recovers 90 percent of variance between actual fuel and purchased power costs and base fuel rate; and, includes forward-looking, historical and transition components.

- Renewable Energy Surcharge ("RES") – recovers costs related to renewable initiatives; collects projected dollars to meet RES targets; and, provides incentives to customers to install distributed renewable energy.

- Demand-Side Management Adjustment Clause ("DSMAC") – recovers costs related to energy efficiency and DSM programs above $10 million in base rates; provides performance incentive to APS for net benefits achieved; and, provides rebates and other incentives to participating customers.

- Environmental Improvement Surcharge ("EIS") – recovers retroactively costs related to environmental upgrades not fully recovered through base rates; and, allows for cost recovery of ACC-approved projects.

- Retail Line Extension Fees – "pay as you go" mechanism collects dollars spent for new distribution construction at beginning of project; and, better protects existing customers by allocating cost of expansion to developers.

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[3] Pinnacle West Capital Corporation, "Delivering Superior Shareholder Value" Investor Meetings, August 10-12, 2011.

- Transmission Cost Adjustor ("TCA") – recovers FERC-approved transmission costs related to retail customers; and, resets annually as result of FERC Formula Rate process.

- FERC Formula Rates – recovers transmission costs based on historical costs per FERC Form 1 and certain projected data; and, resets annually.

Q. Have the rating agencies commented favorably on these mechanisms?

A. Yes. Moody's, for example, stated the following in its February 25, 2011 Global Credit Opinion on APS (Attachment 4):

> Improved Cost Recovery;
>
> Although regulatory lag continues, APS utilizes several mechanisms that allow its rates to be adjusted outside of a general rate case. Moody's generally views these mechanisms as being supportive of credit quality as they tend to result in a more timely recovery of costs. APS' rates are adjusted annually to recover 90% of the difference between its costs for fuel and purchased power and the amounts included in base rates, limiting APS' exposure to volatile power and gas prices. The fuel recovery factor includes a forward estimate of power costs, which further helps to limit cost deferrals; and,
>
> APS also has adjustment mechanisms that allow the utility to recover its costs for renewable energy, efficiency and demand side management programs. Transmission costs are recovered through a transmission cost adjustor which resets annually based on charges in APS' Federal Energy Regulatory Commission approved formula-based tariffs. APS is also currently able to recover its costs for new customer hookups via line extension payments from customers.
>
> In December 2010, the ACC issued a policy statement supporting decoupling rate structures implemented through rate cases over a three year evaluation period. We generally view decoupling mechanisms as supportive to credit quality as they are intended to improve a utility's fixed cost recovery. No Arizona utilities currently have a decoupling mechanism: implementation is intended to occur during the next rate case process.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate-base/rate-of-return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate-base/rate-of-return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (*i.e.*, the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of APS?

A. I have first examined the five year historic (2006-2010) capital structure ratios of APS. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for APS:

	Including S-T Debt	Excluding S-T Debt
2006	52.7%	52.7%
2007	52.0%	53.8%
2008	49.7%	53.9%
2009	50.5%	52.0%
2010	53.1%	56.5%

Page 2 of Schedule 4 shows the capital structure ratios of PWC (Consolidated). The yearly common equity ratios are:

	Including S-T Debt	Excluding S-T Debt
2006	49.7%	50.1%
2007	48.0%	51.7%
2008	46.0%	52.0%
2009	45.6%	48.7%
2010	49.9%	54.7%

These common equity ratios are generally lower than those of APS over the past five years.

Q. How do these capital structures compare to those of investor-owned combination gas/electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of electric utilities covered by AUS Utility Reports. These are:

Year	Electric	Combination Gas And Electric
2006	45%	44%
2007	47%	46%
2008	45%	43%
2009	46%	45%
2010	46%	46%

These common equity ratios are lower than those of APS and PWC.

Q. What capital structure ratios has APS requested in this proceeding?

A. APS is requesting the following capital structure:

Capital Item	Percent
Long-Term Debt	46.06%
Common Equity	53.94%
Total Capital	100.00%

This is the December 31, 2010 capital structure of the Company.

Q. Do you use this capital structure in your cost of capital analyses?

A. Yes, I do.

Q. What is the cost of debt in the company's application?

A. The cost of long-term debt is 6.38 percent. I use this cost rate in my analyses.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for APS?

A. APS is not a publicly-traded company. Consequently, it is not possible to directly apply cost of equity models to this entity. Its parent, PWC, is publicly-traded, so it is possible to directly apply cost of equity models to this entity. However, it is generally preferred to analyze groups of comparison or "proxy" companies as a substitute for APS to determine its cost of common equity.

I have examined two such groups for comparison of APS. I selected one group of electric and combination electric/gas utilities similar to APS and PWC using the criteria listed on Schedule 6. These criteria are as follows:

(1) Market cap of $1 billion to $10 billion;

(2) Electric revenues 50 percent or greater;

(3) Common equity ratio 40 percent or greater;

(4) Value Line Safety Rank of 1, 2 or 3;

(5) S&P stock ranking of A or B;

(6) S&P and Moody's bond ratings of BBB and Baa; and

(7) Currently pays dividends.

Second, I have conducted studies of the cost of equity for the "proxy companies" selected by APS witness Avera.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The discounted cash flow ("DCF") model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)
P = current price
D = current dividend rate
g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for the groups of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; *i.e.*, current versus future dividends, or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (August-October 2011). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2006-2010 (5-year average) earnings retention, or fundamental growth (per Value Line);

2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);

3. 2011, 2012 and 2014-2016 projections of earnings retention growth (per Value Line);

4. 2008-2010 to 2014-2016 projections of EPS, DPS, and BVPS (per Value Line); and

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean Low[4]	Mean High[5]	Median Low[4]	Median High[5]
Proxy Group	8.8%	8.9%	7.4%	9.9%	7.5%	10.6%
Avera Group	9.3%	9.2%	8.5%	10.2%	8.7%	10.0%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 8.8 percent to 9.3 percent. The "low" and "high" DCF rates (i.e., using the lowest and highest

[4] Using only the lowest growth rates.
[5] Using only the highest growth rates.

growth rates only) range from 7.4 percent to 10.6 percent on an average basis and median basis.

Q. What do you conclude from your DCF analysis?

A. This analysis reflects a broad DCF range of 7.4 percent to 10.6 percent for the proxy groups. I give less weight to the extreme lower and upper ends of the DCF results. I believe that a range of 9.3 percent to 10.5 percent (9.9 percent mid-point) reflects the proper DCF cost for APS. This range contains the top mean/median DCF results and contains most of the high DCF results.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The Capital Asset Pricing Model is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity
R_f = risk free rate
Rm = return on market
β = beta
R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies in an industry, such as electric utilities.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. Please explain the risk-free rate as used in your CAPM and indicate what rate you employed.

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (August-October 2011) for 20-year U.S. Treasury bonds. Over this three-month period, these ~~bonds had an average yield of 2.98 percent.~~

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component in your CAPM analysis?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2010 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (*i.e.*, risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.34 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term (20-year) government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2010 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.9%	5.9%	6.0%
Geometric	9.9%	5.5%	4.4%

I conclude from this that the expected risk premium is about 5.58 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Q. Please summarize your CAPM calculations.

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	7.1%	7.0%
Avera Group	7.1%	7.2%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The result of my CAPM analyses collectively indicates a cost of 7.0 percent to 7.2 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for APS is 7.0 percent to 7.2 percent (7.1 percent mid-point).

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original-cost, rate-base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of APS's common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized that utilities that have market-to-book ratios of greater than one (*i.e.,* 100 percent) reflect a situation where a company is able to attract new equity capital without dilution (*i.e.*, above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2010 (*i.e.,* the last nineteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2010 (the recent business cycle) and 1992-2001 (the prior business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Avera Proxy Group
Historic ROE		
Mean	9.6-11.7%	10.4-11.4%
Median	9.5-12.0%	10.2-11.9%
Historic M/B		
Mean	143-164%	164-165%
Median	144-161%	144-159%
Prospective ROE		
Mean	9.0-9.7%	9.4-10.1%
Median	8.3-9.3%	9.0-9.5%

These results indicate that historic returns of 9.5 percent to 12.0 percent have been adequate to produce market-to-book ratios of 143 percent to 165 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2011, 2012, 2014-2016 are within a range of 8.3 percent to 10.1 percent for the utility groups. These relate to 2010 market-to-book ratios of 118 percent or higher.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past nineteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 12.4 percent to 14.7 percent with market-to-book ratios ranging between 258 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for APS?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.0 percent. Recent returns of 9.5 percent to 12.0 percent have resulted in market-to-book ratios of 143 and greater. Prospective returns of 8.3 percent to 10.1 percent result in anticipated market-to-book ratios of over 118 percent. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9.5 percent to 10.0 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematical formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.0 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for APS/PWC. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

	Range	Mid-Point
Discounted Cash Flow	9.3-10.5%	9.90%
Capital Asset Pricing Model	7.0-7.2%	7.10%
Comparable Earnings	9.5-10.0%	9.75%

Q. What is your cost of equity recommendation for APS?

A. My analyses suggest a broad cost of equity range of 7.0 percent to 10.5 percent range for APS. The respective mid-points of my DCF and CE analyses are 9.90 percent and 9.75 percent. I recommend a cost of equity range of 9.3 percent to 10.5 percent (9.90 percent mid-point) for APS. This range is supported by my DCF and CE analyses, and exceeds my CAPM findings. I believe a 9.90 cost of equity is adequate at this time in order to give some consideration to APS's ratepayers for the economic distress they are incurring due to the recent recession and at same time assist APS maintain, if not improve, its debt rating.

Q. It appears that your CAPM results are somewhat lower than your DCF results. Does this indicate that the CAPM results should not be used at this time?

A. No, this is not the case. Although my recommended range is above the CAPM results, I have not disregarded the CAPM results. It is apparent that the CAPM results are lower than the DCF results, as well as being lower than CAPM results in recent years. The two reasons for this are the current relatively low yields on U.S. Treasury bonds (i.e., risk-free rate) and a lower risk premium that reflects the decline in stock prices of the past few years. However, these currently lower CAPM results are only one-half of the impact of recent economic conditions. The other impact is on the DCF results, which are somewhat higher currently due to the higher yields attributable to the decline in stock prices, as well as the use of EPS projections from a depressed base (beginning) point. It would not be proper to disregard the lower CAPM results while not discounting the higher DCF results.

Q. How does your cost of equity recommendation in this proceeding compare to your cost of equity recommendation in the last APS general rate proceeding?

A. As I indicated above, my cost of capital range in the current proceeding is 9.3 percent to 10.5 percent, with a mid-point of 9.90 percent. In addition, the mid-points of my DCF and CE analyses are 9.90 percent and 9.75 percent, respectively. I am recommending a point estimate of 9.90 percent for APS in this proceeding.

In the last general rate proceeding of APS (Docket No. E-01345A-08-0172), my corresponding cost of equity range was 9.0 percent to 11.0 percent, with a mid-point of 10.0 percent. In that proceeding, I recommended the top of the range, or 11.0 percent. As I indicated (pages 32-33)

> Even though a lower cost of equity (e.g., the mid-point of my 9.0 percent to 11.0 percent range) could be justified, my 11.0 percent recommendation reflects Staffs desire to aid APS in its efforts to attract capital investment, as cited in the testimony of Staff witness Johnson.

I have also demonstrated, in prior sections of my prior testimony, that the financial circumstances of APS are improved currently in comparison to those in existence in the prior general rate proceeding. As I indicated, APS' debt ratings and outlooks have improved and that PWC has successfully raised common equity in the capital markets. As a result, I do not propose any similar adjustment to the top end of the cost of capital range, nor is Staff proposing such an adjustment, in the current proceeding.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for APS?

A. Schedule 1 reflects the total cost of capital for the Company using APS's test period capital structure along with the cost of debt and common equity costs my analyses support. The resulting total cost of capital is 7.95 percent to 8.60 percent (8.28 percent with 9.90 percent return on equity). I recommend that this 8.28 percent total cost of capital be established for APS.

Q. Does your cost of capital recommendation provide the Company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 13 shows the pre-tax coverage that would result if APS earned my cost of capital recommendation. As the results indicate, my recommended range would exceed a coverage level above the benchmark range for a BBB rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) exceeds the benchmark for a BBB rated utility.

XIII. CRITIQUE OF COMPANY TESTIMONY

Q. Have you reviewed the testimony of APS witness William Avera?

A. Yes, I have.

Q. What is your understanding of Dr. Avera's cost of equity recommendation for APS?

A. Dr. Avera proposes an equity return for APS of 11.25 percent.

Q. Please summarize your understanding of Dr. Avera's cost of equity analyses.

A. Dr. Avera's cost of equity findings can be summarized as follows:

	Utility Proxy Group	Non-Utility Proxy Group
DCF		
Earnings		
Value Line	11.2%	11.9%
IBES	11.0%	12.4%
Zacks	10.9%	12.5%
br + sv	9.5%	12.1%
CAPM	11.4%	10.0%

Based upon these results, Dr. Avera concluded that the "bare bones" cost of equity is a range of 10.6 percent to 11.6 percent. He adds 0.15 percent to this range for flotation costs and concludes the cost of equity is 10.75 percent to 11.75 percent. He further concludes that the cost of equity for APS is the mid-point of this range, or 11.25 percent.

Q. Do you have any comments concerning Dr. Avera's DCF analyses and conclusions?

A. Yes, I do. Dr. Avera's DCF analyses for his utility proxy group contains an 11.0 percent conclusion. This 11.0 percent conclusion is based on his four sets of DCF analyses shown on his page 48. All but one of these sets of DCF analyses are based exclusively on analysts' forecasts of EPS growth and the remaining DCF result is 9.5 percent for his utility proxy group. It is thus obvious that Dr. Avera's 11.25 percent DCF conclusion is based almost exclusively on analysts' forecasts of EPS growth.

Q. Is it proper to focus on analysts' forecasts of EPS growth in a DCF analysis?

A. No. As I indicated in my DCF analysis, it is customary and proper to use alternative measures of growth, not just EPS projections.

Dr. Avera's DCF analyses implicitly assume that investors rely almost exclusively on EPS projections when making investment decisions. This is a very dubious assumption, and Dr. Avera has offered no evidence that it is correct. I note, for example, the Value Line publication – one of the sources of his growth rate estimates – contains many statistics, of both a historic and projected nature, for the benefit of Value Line subscribers, who presumably make investment decisions based at least in part from the information contained in Value Line. For example, Value Line publishes both historic and projected growth rates in numerous financial indicators such as EPS, DPS, BVPS, and retention growth. Yet, Dr. Avera would have us believe that Value Line subscribers and investors focus exclusively on one single number from this publication.

I note in this regard that the DCF model is a "cash flow" model. The cash flow to investors in a DCF framework is dividends. Dr. Avera's DCF results, in contrast, does not even consider dividend growth rates.

Q. Dr. Avera also conducts DCF analyses to a group of non-regulated companies. Is this a proper standard for establishing APS' cost of equity?

A. No, it is not. This group of non-regulated companies is clearly more risky than his proxy group of electric utilities. As evidence of this, consider the respective sets of DCF analyses for the two groups, as referenced above.

The DCF costs for the non-utility group are much higher than those for the electric group. This clearly indicates that the non-utility group is more risky than the utility group and, thus, serves as no reliable standard for APS.

Q. What are your comments regarding Dr. Avera's CAPM analysis?

A. Dr. Avera's CAPM uses the following inputs for his utility proxy group:

Market risk premium	8.3%
Risk free rate	4.5%
Beta	0.74%
Size Adjustment	0.74%

My first concern with Dr. Avera's CAPM analysis is the use of the 8.3 percent market risk premium. His 8.3 percent market risk premium was derived by combining his estimate of DCF results for the S&P 500 (12.8 percent) and a 4.5 percent yield on 30-year U.S. Treasury bonds. This 12.8 percent expected return for the S&P 500 is excessive. The historic (1926-2010) total returns for the S&P 500 have been much less than 12.8 percent (i.e., 9.9 percent on a geometric growth basis and 11.9 percent on an arithmetic basis). Dr. Avera offers no explanation as to why his DCF results for the S&P 500 group are so much higher than his group's historic returns.

XIV. FAIR VALUE RATE OF RETURN

Q. What is your understanding of APS's position on the issue of fair value rate base and related rate of return implications?

A. It is my understanding that APS is requesting that the fair value of its rate base be used in developing its rates. The Company is requesting that the Commission use the same methodology for determining its fair value rate of return ("FVROR") as was used by the Staff in the last APS case. The Company is requesting a 1.0 percent return on its fair value increment of capital (i.e., the difference between the Reconstructed Cost New ("RCN") rate base and Original Cost ("OC") rate base).

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. My understanding is based in part on the 2007 Arizona Court of Appeals decision in the Chaparral City case that indicates that the court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ."[6] The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology."[7] It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon nearly 40 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds

[6] Chaparral City Water Company v. ACC, 1 CA-0005-0002, at p. 13, #17 (Ariz. App. Feb 13, 2007)(memo decision)
[7] Id.

original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and the Arizona Court of Appeals have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 40 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for APS?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to APS's FVRB.

Item	Percent[8]	Cost	Fair Value Return
Long-term Debt	31.94%	6.38%	2.04%
Common Equity	37.40%	9.90%	3.70%
FVRB Increment[9]	30.66%	0.00%	0.00%
Total FVRB Capital	100.00%		5.74%

Applying this 5.74 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB. Staff also refers to this as Method 1.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the

[8] As shown in Testimony of Utilities Division Staff witness Ralph Smith.
[9] FVRB minus OCRB.

OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the Fair Value Increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that APS may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.1 percent (short-term) to 4.0 percent (long-term) in nominal terms. I also note that 2011 and 2012 forecasts of long-term U.S. Treasury securities are about 3.5 percent to 5.0 percent. As a result, I use 4.0 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2010, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 1.5 percent. Forecasts of the CPI for 2011-2012 are about 2 percent or less. As a result, I propose to use a 2 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.0%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.0%

Q. Please explain why APS's FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of APS are already receiving an inflation factor due to the inclusion of inflation in the Fair Value Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the Fair Value Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal ("Method 2") incorporates a return on the Fair Value Increment with a maximum value of 2.0 percent, as developed above. However, I wish to emphasize that this 2.0 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.0 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.00 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for APS:

Capital Item	Percent	Cost	Return
Long-term Debt	31.94%	6.38%	2.04%
Common Equity	37.40%	9.90%	3.70%
FVRB Increment	30.66%	1.00%	0.31%
Total	100.00%		6.05%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of APS, and provides for an overall fair value rate of return of 6.05 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. On the other hand, if the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.00 percent cost-rate for the FVRB increment) is not inappropriate. It is my understanding that this second alternative was utilized by the Commission in APS's last rate proceeding.

Q. Do these proposals provide for a return on the FVRB of APS?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair value increment, it may be appropriate to determine the cost of equity to reflect a reduction in risk. I have not proposed such an adjustment in this case, but these issues may appear as Staff continues to consider appropriate methods for determining and evaluating the concept of fair value rate of return on fair value rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATION

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

ARIZONA PUBLIC SERVICE COMPANY
TOTAL COST OF CAPITAL
FOR THE TEST YEAR ENDED DECEMBER 31, 2010

Capital Item	Amount 1/ ($000)	Percent	Cost Rate			Weighted Cost		
Long-Term Debt	$3,382,856	46.06%		6.38%	1/		2.94%	
Short-Term Debt	$0	0.00%		--	1/		--	
Common Equity	$3,961,248	53.94%	9.30%	9.90%	10.50%	5.02%	5.34%	5.66%
Total Capital	$7,344,104	100.00%				**7.95%**	**8.28%**	**8.60%**

1/ As contained in Schedule D-1 of Company Filing.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.4%	6.9%	2.7%	0.2%
1994	4.0%	5.5%	6.1%	2.7%	1.7%
1995	3.7%	4.8%	5.6%	2.5%	2.3%
1996	4.5%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	3.7%	4.5%	4.2%	2.7%	2.9%
2000	4.1%	4.0%	4.0%	3.4%	3.6%
2001	1.1%	-3.3%	4.7%	1.6%	-1.6%
		2002 - 2009 Cycle			
2002	1.8%	0.2%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.5%	2.3%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.7%	2.2%	4.6%	2.5%	1.1%
2007	1.9%	2.7%	4.6%	4.1%	6.2%
2008	-0.3%	-3.7%	5.8%	0.1%	-0.9%
2009	-3.5%	-11.2%	9.3%	2.7%	4.3%
		Current Cycle			
2010	3.0%	5.3%	9.6%	1.5%	3.8%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%	10.8%
2008					
1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.7%	-11.6%	8.1%	2.4%	-0.4%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.2%	9.2%
3rd Qtr.	1.7%	-9.3%	9.6%	2.0%	-0.8%
4th Qtr.	3.8%	-4.5%	10.0%	2.5%	8.8%
2010					
1st Qtr.	3.9%	2.7%	9.7%	0.9%	6.5%
2nd Qtr.	3.8%	7.4%	9.7%	-1.5%	-3.5%
3rd Qtr.	2.5%	6.9%	9.6%	2.8%	4.3%
4th Qtr.	2.3%	6.3%	9.6%	2.8%	8.0%
2011					
1st Qtr.	0.4%	5.4%	8.9%	5.6%	13.2%
2nd Qtr.	1.3%	3.8%	9.1%	1.6%	2.4%
3rd Qtr.			9.1%		

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2009							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%		6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%		5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%		5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%		5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%		5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%		5.33%	5.64%	6.18%
Dec	3.25%	0.07%	3.59%		5.52%	5.79%	6.26%
2010							
Jan	3.25%	0.06%	3.73%		5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%		5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%		5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%		5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%		5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%		5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%		4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%		4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%		4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%		4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%		5.12%	5.37%	5.85%
Dec	3.25%	0.14%	3.29%		5.32%	5.56%	6.04%
2011							
Jan	3.25%	0.15%	3.39%		5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%		5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%		5.33%	5.56%	5.97%
Apr	3.25%	0.06%	3.46%		5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%		5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%		5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%		5.05%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%		4.44%	4.69%	5.22%
Sept	3.25%	0.02%	1.98%		4.24%	4.48%	5.11%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
			1975 - 1982 Cycle		
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
			1983 - 1991 Cycle		
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
			1992 - 2001 Cycle		
1992	$415.74	$599.26	3,284.29	2.99%	4.22%
1993	$451.21	715.16	3,522.06	2.78%	4.46%
1994	$460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22		10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
			2002 - 2009 Cycle		
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
			Current Cycle		
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,228.12	2,613.11	11,671.47	2.15%	

Source: Council of Economic Advisors, Economic Indicators, various issues.

Exhibit___(DCP-1)
Schedule 3

ARIZONA PUBLIC SERVICE AND PINNACLE WEST CAPITAL SECURITY RATINGS

	Moody's		Standard & Poor's	
Date	APS	PWC	APS	PWC
2000	Baa2		BBB	
2001	Baa2/Baa1		BBB	
2002	Baa1		BBB	
2003	Baa1		BBB	
2004	Baa1		BBB	
2005	Baa1		BBB/BBB-	
2006	Baa1/Baa2		BBB-	BBB-
2007	Baa2	Baa3	BBB-	BBB-
2008	Baa2	Baa3	BBB-	BBB-
2009	Baa2	Baa3	BBB-	BBB-
2010	Baa2	Baa3	BBB-	BBB-
2011	Baa2	Baa3	BBB-/BBB	BBB-/BBB

Source: Response to Staff 2.5.

ARIZONA PUBLIC SERVICE COMPANY
CAPITAL STRUCTURE RATIOS
2006 - 2010
($ 000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2006	$3,207,473	$2,877,502	$968
	52.7%	47.3%	0.0%
	52.7%	47.3%	
2007	$3,351,441	$2,876,881	$218,978
	52.0%	44.6%	3.4%
	53.8%	46.2%	
2008	$3,339,150	$2,850,242	$522,558
	49.7%	42.5%	7.8%
	53.9%	46.1%	
2009	$3,445,355	$3,180,406	$197,176
	50.5%	46.6%	2.9%
	52.0%	48.0%	
2010	$3,824,953	$2,948,991	$427,682
	53.1%	40.9%	5.9%
	56.5%	43.5%	

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Staff 2.4.

PINNACLE WEST CAPITAL CORP.
CAPITAL STRUCTURE RATIOS
2006 - 2010
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2006	$3,446,116 49.7% 50.1%	$3,426,914 49.4% 49.9%	$57,505 0.8%
2007	$3,531,611 48.0% 51.7%	$3,300,663 44.9% 48.3%	$525,177 7.1%
2008	$3,445,979 46.0% 52.0%	$3,183,386 42.4% 48.0%	$869,870 11.6%
2009	$3,316,109 45.6% 48.7%	$3,496,254 48.1% 51.3%	$457,191 6.3%
2010	$3,683,327 49.9% 54.7%	$3,045,794 41.3% 45.3%	$648,479 8.8%

Note: Percentages may not total 100.0% due to rounding.

Source: Response to Staff 2.4.

Exhibit___(DCP-1)
Schedule 5

AUS UTILITY REPORTS
ELECTRIC UTILITY GROUPS
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Year	Electric	Combination Gas & Electric
2006	45%	44%
2007	47%	46%
2008	45%	43%
2009	46%	45%
2010	46%	46%

Source: AUS Utility Reports.

COMPARISON COMPANIES
BASIS FOR SELECTION

Company	Market Cap ($000) (1)	Percent Revenues Electric (2)	Common Equity Ratio (3)	Value Line Safety Rank (4)	S&P Stock Ranking (5)	Moody's/ S&P Bond Rating (6)
Pinnacle West Capital	$4,700,000	97%	55%	2	B	Baa2/BBB-
Arizona Public Service Co.			56%			Baa2/BBB
Proxy Group						
Ameren	$6,900,000	85%	51%	3	B	Baa2/BBB-
Avista Corp.	$1,400,000	63%	48%	2	A-	Baa1/BBB+
Cleco Corp.	$2,100,000	98%	49%	2	B	Baa2/BBB
Great Plains Energy	$2,800,000	100%	49%	3	B	Baa2/BBB
Hawaiian Electric Industries	$2,400,000	89%	54%	3	B	Baa2/BBB-
OGE Energy	$4,800,000	57%	49%	2	A-	Baa1/BBB+
TECO Energy	$4,100,000	84%	41%	3	B	Baa1/BBB
UIL Holdings	$1,700,000	86%	42%	2	B	Baa2/nr
Westar Energy	$3,000,000	100%	46%	2	B	Baa1/BBB+

Criteria For Selection:
Market Cap of $1 billion to $10 billion.
Percent electric revenues of 50% or greater
Common equity ratio of 40% or greater
Value Line Safety Rank of 1, 2, or 3
S&P Stock Ranking of A or B
Moody's and S&P Bond Rating of Baa and BBB.
Currently pays common stock dividends.

Sources:
(1) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(2) AUS Utility Reports, April, 2011 edition, year-end 2010 data.
(3) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions, excludes short-term debt.
(4) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(5) Value Line - May 27, 2011, June 24, 2011 and May 6, 2011 editions.
(6) AUS Utility Reports, August, 2011 edition.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	Quarterly DPS	DPS	August - October, 2011 HIGH	LOW	AVERAGE	YIELD
Proxy Group						
Ameren	$0.385	$1.540	$32.53	$25.55	$29.04	5.3%
Avista Corp.	$0.275	$1.100	$26.35	$21.13	$23.74	4.6%
Cleco Corp.	$0.280	$1.120	$37.74	$30.06	$33.90	3.3%
Great Plains Energy	$0.208	$0.832	$21.33	$16.34	$18.84	4.4%
Hawaiian Electric Industries	$0.310	$1.240	$25.91	$20.59	$23.25	5.3%
OGE Energy	$0.375	$1.500	$53.62	$40.56	$47.09	3.2%
Pinnacle West Capital	$0.525	$2.100	$47.36	$37.28	$42.32	5.0%
TECO Energy	$0.215	$0.860	$18.97	$15.82	$17.40	4.9%
UIL Holdings	$0.432	$1.728	$34.90	$29.00	$31.95	5.4%
Westar Energy	$0.320	$1.280	$27.73	$22.63	$25.18	5.1%
Average						**4.7%**
Avera Proxy Group						
Ameren	$0.385	$1.540	$32.53	$25.55	$29.04	5.3%
American Electric Power	$0.460	$1.840	$40.00	$33.09	$36.55	5.0%
CenterPoint Energy	$0.198	$0.792	$21.39	$17.11	$19.25	4.1%
Cleco	$0.280	$1.120	$37.74	$30.06	$33.90	3.3%
CMS Energy	$0.210	$0.840	$21.58	$16.96	$19.27	4.4%
Constellation Energy	$0.240	$0.960	$40.20	$33.84	$37.02	2.6%
DTE Energy	$0.588	$2.352	$52.82	$43.22	$48.02	4.9%
Edison International	$0.320	$1.280	$41.57	$32.64	$37.11	3.4%
Great Plains Energy	$0.208	$0.832	$21.33	$16.34	$18.84	4.4%
Hawaiian Electric Industries	$0.310	$1.240	$25.91	$20.59	$23.25	5.3%
IDACORP	$0.300	$1.200	$41.97	$33.88	$37.93	3.2%
Integrys Energy Group	$0.680	$2.720	$54.00	$42.76	$48.38	5.6%
ITC Holdings	$0.353	$1.412	$78.89	$64.88	$71.89	2.0%
Pepco Holdings	$0.270	$1.080	$20.33	$16.57	$18.45	5.9%
PG&E Corp	$0.455	$1.820	$43.82	$37.57	$40.70	4.5%
Pinnacle West Capital	$0.525	$2.100	$47.36	$37.28	$42.32	5.0%
Portland General	$0.265	$1.060	$25.18	$21.29	$23.24	4.6%
PPL Corp	$0.350	$1.400	$29.78	$25.00	$27.39	5.1%
TECO Energy	$0.215	$0.860	$18.97	$15.82	$17.40	4.9%
Westar Energy	$0.320	$1.280	$27.73	$22.63	$25.18	5.1%
Wisconsin Energy	$0.260	$1.040	$33.63	$27.00	$30.32	3.4%
Average						**4.4%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2006	2007	2008	2009	2010	Average	2011	2012	2014-'16	Average
Proxy Group										
Ameren	0.2%	1.3%	1.0%	3.5%	3.8%	2.0%	2.5%	2.5%	2.5%	2.5%
Avista Corp.	4.9%	0.8%	3.7%	4.1%	3.3%	3.4%	3.5%	3.0%	2.5%	3.0%
Cleco Corp.	3.0%	2.6%	4.5%	4.7%	6.1%	4.2%	5.5%	5.0%	4.0%	4.8%
Great Plains Energy	0.0%	0.9%	0.0%	0.9%	3.4%	1.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric Industries	0.7%	0.8%	0.5%	0.0%	1.4%	0.7%	0.5%	1.5%	3.5%	1.8%
OGE Energy	6.6%	7.1%	5.4%	6.0%	6.7%	6.4%	8.0%	6.5%	6.5%	7.0%
Pinnacle West Capital	3.4%	2.5%	0.3%	0.7%	3.1%	2.0%	2.0%	3.5%	3.0%	2.8%
TECO Energy	5.0%	5.1%	0.0%	2.1%	3.1%	3.1%	4.5%	5.5%	5.5%	5.2%
UIL Holdings	0.0%	3.1%	1.0%	1.2%	1.7%	1.4%	1.0%	1.0%	2.5%	1.5%
Westar Energy	5.5%	4.3%	1.2%	0.8%	2.8%	2.9%	2.0%	2.5%	4.0%	2.8%
Average						**2.7%**				**3.4%**
Avera Proxy Group										
Ameren	0.2%	1.3%	1.0%	3.5%	3.8%	2.0%	2.5%	2.5%	2.5%	2.5%
American Electric Power	5.7%	5.1%	5.1%	4.6%	3.1%	4.7%	4.5%	4.5%	5.0%	4.7%
CenterPoint Energy	15.7%	10.0%	9.9%	3.6%	3.8%	8.6%	4.0%	4.0%	4.0%	4.0%
Cleco	3.0%	2.6%	4.5%	4.7%	6.1%	4.2%	5.5%	5.0%	4.0%	4.8%
CMS Energy	6.4%	5.1%	8.4%	4.1%	6.9%	6.2%	5.5%	5.5%	5.0%	5.3%
Constellation Energy	9.1%	8.9%	0.0%	1.5%	1.8%	4.3%	3.5%	3.5%	5.5%	4.2%
DTE Energy	1.2%	1.5%	1.7%	2.9%	4.0%	2.3%	3.0%	3.0%	3.5%	3.2%
Edison International	10.1%	9.2%	8.6%	6.7%	6.5%	8.2%	4.5%	4.5%	4.5%	4.5%
Great Plains Energy	0.0%	0.9%	0.0%	0.9%	3.4%	1.0%	2.0%	2.5%	3.0%	2.5%
Hawaiian Electric Industries	0.7%	0.8%	0.5%	0.0%	1.4%	0.7%	0.5%	1.5%	3.5%	1.8%
IDACORP	4.3%	2.4%	3.4%	4.8%	5.5%	4.1%	6.0%	5.5%	4.5%	5.3%
Integrys Energy Group	3.4%	0.0%	0.0%	0.0%	2.3%	1.1%	1.5%	2.0%	3.0%	2.2%
ITC Holdings	0.0%	4.5%	5.4%	6.8%	7.1%	4.8%	8.0%	9.5%	11.0%	9.5%
Pepco Holdings	1.5%	2.3%	4.2%	0.0%	0.8%	1.8%	1.0%	1.0%	2.5%	1.5%
PG&E Corp	6.8%	6.0%	6.8%	5.5%	3.9%	5.8%	3.0%	5.5%	5.5%	4.7%
Pinnacle West Capital	3.4%	2.5%	0.3%	0.7%	3.1%	2.0%	2.0%	3.5%	3.0%	2.8%
Portland General	3.5%	6.6%	2.0%	1.5%	3.0%	3.3%	4.5%	4.5%	4.0%	4.3%
PPL Corp	9.3%	10.0%	8.5%	0.0%	5.2%	6.6%	5.5%	5.5%	5.0%	5.3%
TECO Energy	5.0%	5.1%	0.0%	2.1%	3.1%	3.1%	4.5%	5.5%	5.5%	5.2%
Westar Energy	5.5%	4.3%	1.2%	0.8%	2.8%	2.9%	2.0%	2.5%	4.0%	2.8%
Wisconsin Energy	7.1%	7.1%	7.0%	6.2%	7.0%	6.9%	6.5%	6.5%	6.0%	6.3%
Average						**4.0%**				**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '08-'10 to '14-'16 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Proxy Group								
Ameren	-1.5%	-6.0%	2.5%	-1.7%	-2.0%	-3.0%	1.5%	-1.2%
Avista Corp.	11.5%	10.0%	4.0%	8.5%	4.5%	9.0%	3.0%	5.5%
Cleco Corp.	7.5%	0.5%	11.0%	6.3%	6.0%	9.5%	6.5%	7.3%
Great Plains Energy	-11.5%	-8.0%	7.0%	-4.2%	6.0%	0.0%	2.0%	2.7%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	11.0%	1.0%	2.5%	4.8%
OGE Energy	9.0%	1.5%	8.5%	6.3%	6.5%	4.0%	7.5%	6.0%
Pinnacle West Capital	0.5%	3.0%	0.5%	1.3%	6.0%	1.5%	2.5%	3.3%
TECO Energy	12.0%	-0.5%	5.0%	5.5%	10.5%	4.5%	5.0%	6.7%
UIL Holdings	7.5%	0.0%	-2.0%	1.8%	3.0%	0.0%	5.5%	2.8%
Westar Energy	1.0%	7.0%	6.0%	4.7%	8.5%	3.0%	2.0%	4.5%
Average				**2.7%**				**4.3%**
Avera Proxy Group								
Ameren	-1.5%	-6.0%	2.5%	-1.7%	-2.0%	-3.0%	1.5%	-1.2%
American Electric Power	2.0%	2.0%	5.0%	3.0%	4.5%	4.0%	4.5%	4.3%
CenterPoint Energy	5.0%	13.5%	8.5%	9.0%	3.0%	3.0%	10.0%	5.3%
Cleco	7.5%	0.5%	11.0%	6.3%	6.0%	9.5%	6.5%	7.3%
CMS Energy	17.5%		1.5%	9.5%	7.0%	14.0%	5.0%	8.7%
Constellation Energy	-16.0%	1.5%	4.5%	-3.3%	18.0%	-4.0%	6.5%	6.8%
DTE Energy	2.5%	1.0%	3.5%	2.3%	4.5%	4.0%	3.5%	4.0%
Edison International	10.0%	15.5%	10.5%	12.0%	-1.0%	2.0%	4.5%	1.8%
Great Plains Energy	-11.5%	-8.0%	7.0%	-4.2%	6.0%	0.0%	2.0%	2.7%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	11.0%	1.0%	2.5%	4.8%
IDACORP	11.0%	-2.5%	4.5%	4.3%	4.0%	4.0%	5.0%	4.3%
Integrys Energy Group	-8.0%	4.0%	5.5%	0.5%	9.0%	0.0%	1.5%	3.5%
ITC Holdings					14.0%	5.5%	10.5%	10.0%
Pepco Holdings	-0.5%	1.5%	1.0%	0.7%	2.5%	1.0%	2.0%	1.8%
PG&E Corp	7.0%		10.5%	8.8%	6.0%	4.5%	5.5%	5.3%
Pinnacle West Capital	0.5%	3.0%	0.5%	1.3%	6.0%	1.5%	2.5%	3.3%
Portland General	7.5%		2.0%	4.8%	7.5%	3.0%	3.5%	4.7%
PPL Corp	1.0%	10.0%	7.0%	6.0%	7.0%	3.5%	9.0%	6.5%
TECO Energy	12.0%	-0.5%	5.0%	5.5%	10.5%	4.5%	5.0%	6.7%
Westar Energy	1.0%	7.0%	6.0%	4.7%	8.5%	3.0%	2.0%	4.5%
Wisconsin Energy	8.5%	10.0%	7.5%	8.7%	8.5%	16.0%	4.5%	9.7%
Average				**3.8%**				**5.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Proxy Group								
Ameren	5.4%	2.0%	2.5%			1.0%	1.8%	7.2%
Avista Corp.	4.7%	3.4%	3.0%	8.5%	5.5%	4.7%	5.0%	9.8%
Cleco Corp.	3.4%	4.2%	4.8%	6.3%	7.3%	3.0%	5.1%	8.5%
Great Plains Energy	4.5%	1.0%	2.5%		2.7%	5.8%	3.0%	7.5%
Hawaiian Electric Industries	5.4%	0.7%	1.8%		4.8%	8.6%	4.0%	9.4%
OGE Energy	3.3%	6.4%	7.0%	6.3%	6.0%	7.4%	6.6%	9.9%
Pinnacle West Capital	5.0%	2.0%	2.8%	1.3%	3.3%	6.3%	3.2%	8.2%
TECO Energy	5.1%	3.1%	5.2%	5.5%	6.7%	5.7%	5.2%	10.3%
UIL Holdings	5.5%	1.4%	1.5%	1.8%	2.8%	4.1%	2.3%	7.8%
Westar Energy	5.2%	2.9%	2.8%	4.7%	4.5%	5.2%	4.0%	9.2%
Mean	4.7%	2.7%	3.4%	4.9%	4.9%	5.2%	4.0%	**8.8%**
Median	5.1%	2.5%	2.8%	5.5%	4.8%	5.4%	4.0%	**8.9%**
Composite - Mean		**7.4%**	8.1%	9.7%	9.6%	**9.9%**	8.8%	
Composite - Median		**7.5%**	7.9%	**10.6%**	9.9%	10.5%	9.1%	
Avera Proxy Group								
Ameren	5.4%	2.0%	2.5%			1.0%	1.8%	7.2%
American Electric Power	5.1%	4.7%	4.7%	3.0%	4.3%	4.3%	4.2%	9.3%
CenterPoint Energy	4.3%	8.6%	4.0%	9.0%	5.3%	6.4%	6.7%	10.9%
Cleco	3.4%	4.2%	4.8%	6.3%	7.3%	3.0%	5.1%	8.5%
CMS Energy	4.5%	6.2%	5.3%	9.5%	8.7%	6.0%	7.1%	11.7%
Constellation Energy	2.7%	4.3%	4.2%		6.8%	4.5%	4.9%	7.6%
DTE Energy	5.0%	2.3%	3.2%	2.3%	4.0%	3.4%	3.0%	8.0%
Edison International	3.6%	8.2%	4.5%	12.0%	1.8%	2.9%	5.9%	9.4%
Great Plains Energy	4.5%	1.0%	2.5%		2.7%	5.8%	3.0%	7.5%
Hawaiian Electric Industries	5.4%	0.7%	1.8%		4.8%	8.6%	4.0%	9.4%
IDACORP	3.2%	4.1%	5.3%	4.3%	4.3%	4.7%	4.6%	7.8%
Integrys Energy Group	5.7%	1.1%	2.2%	0.5%	3.5%	9.4%	3.3%	9.1%
ITC Holdings	2.1%	4.8%	9.5%		10.0%	18.0%	10.6%	12.6%
Pepco Holdings	5.9%	1.8%	1.5%	0.7%	1.8%	7.5%	2.7%	8.6%
PG&E Corp	4.6%	5.8%	4.7%	8.8%	5.3%	3.8%	5.7%	10.3%
Pinnacle West Capital	5.0%	2.0%	2.8%	1.3%	3.3%	6.3%	3.2%	8.2%
Portland General	4.7%	3.3%	4.3%	4.8%	4.7%	5.3%	4.5%	9.1%
PPL Corp	5.2%	6.6%	5.3%	6.0%	6.5%	0.0%	4.9%	10.1%
TECO Energy	5.1%	3.1%	5.2%	5.5%	6.7%	5.7%	5.2%	10.3%
Westar Energy	5.2%	2.9%	2.8%	4.7%	4.5%	5.2%	4.0%	9.2%
Wisconsin Energy	3.6%	6.9%	6.3%	8.7%	9.7%	7.3%	7.8%	11.3%
Mean	4.5%	4.0%	4.2%	5.5%	5.3%	5.7%	4.9%	**9.3%**
Median	4.7%	4.1%	4.3%	5.1%	4.8%	5.3%	4.6%	**9.2%**
Composite - Mean		**8.5%**	8.6%	9.9%	9.8%	**10.2%**	9.3%	
Composite - Median		**8.7%**	9.0%	9.8%	9.4%	**10.0%**	9.2%	

Note: Negative growth rates excluded from analyses

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
Average					**6.34%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE 1/	BETA	RISK PREMIUM	CAPM RATES
Proxy Group				
Ameren	2.98%	0.80	5.58%	7.4%
Avista Corp.	2.98%	0.70	5.58%	6.9%
Cleco Corp.	2.98%	0.65	5.58%	6.6%
Great Plains Energy	2.98%	0.75	5.58%	7.2%
Hawaiian Electric Industries	2.98%	0.70	5.58%	6.9%
OGE Energy	2.98%	0.75	5.58%	7.2%
Pinnacle West Capital	2.98%	0.70	5.58%	6.9%
TECO Energy	2.98%	0.85	5.58%	7.7%
UIL Holdings	2.98%	0.70	5.58%	6.9%
Westar Energy	2.98%	0.75	5.58%	7.2%
Mean				**7.1%**
Median				**7.0%**
***Avera* Proxy Group**				
Ameren	2.98%	0.80	5.58%	7.4%
American Electric Power	2.98%	0.70	5.58%	6.9%
CenterPoint Energy	2.98%	0.80	5.58%	7.4%
Cleco	2.98%	0.65	5.58%	6.6%
CMS Energy	2.98%	0.75	5.58%	7.2%
Constellation Energy	2.98%	0.80	5.58%	7.4%
DTE Energy	2.98%	0.75	5.58%	7.2%
Edison International	2.98%	0.80	5.58%	7.4%
Great Plains Energy	2.98%	0.75	5.58%	7.2%
Hawaiian Electric Industries	2.98%	0.70	5.58%	6.9%
IDACORP	2.98%	0.70	5.58%	6.9%
Integrys Energy Group	2.98%	0.90	5.58%	8.0%
ITC Holdings	2.98%	0.80	5.58%	7.4%
Pepco Holdings	2.98%	0.80	5.58%	7.4%
PG&E Corp	2.98%	0.55	5.58%	6.0%
Pinnacle West Capital	2.98%	0.70	5.58%	6.9%
Portland General	2.98%	0.75	5.58%	7.2%
PPL Corp	2.98%	0.65	5.58%	6.6%
TECO Energy	2.98%	0.85	5.58%	7.7%
Westar Energy	2.98%	0.75	5.58%	7.2%
Wisconsin Energy	2.98%	0.65	5.58%	6.6%
Mean				**7.1%**
Median				**7.2%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

1/ Average yield on 20-Year U.S. Treasury Bonds:

Aug., 2011	3.24%
Sept., 2011	2.83%
Oct., 2011	2.87%
Average	2.98%

Exhibit___(DCP-1)
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COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average	2011	2012	2014-1
Proxy Group																								
Ameren	12.7%	12.9%	13.7%	13.1%	12.5%	10.8%	12.7%	12.5%	14.5%	14.3%	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	13.0%	9.6%	7.0%	7.0%	7.0%
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.4%	8.5%	10.4%	6.6%	9.0%	8.5%	9.0%
Cleco Corp.	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.4%	8.2%	9.9%	9.7%	11.4%	13.4%	10.9%	10.0%	10.0%	9.5%
Great Plains Energy	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	14.2%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	11.8%	11.3%	5.5%	6.5%	7.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	5.9%	7.7%	11.0%	8.8%	8.0%	9.0%	10.5%
OGE Energy	10.8%	12.4%	13.3%	13.2%	13.8%	13.4%	16.3%	14.9%	14.1%	9.6%	11.1%	13.2%	12.7%	12.4%	14.9%	14.7%	12.9%	12.9%	13.4%	13.2%	13.1%	14.0%	12.5%	12.0%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	11.5%	8.0%	8.0%	9.0%	9.0%
TECO Energy	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	10.4%	11.4%	15.6%	10.6%	12.5%	13.5%	13.0%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	10.2%	9.8%	10.8%	8.8%	8.5%	8.5%	9.0%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	6.7%	8.4%	7.5%	8.5%	10.0%
Average	11.7%	12.1%	11.9%	12.5%	12.1%	11.0%	11.8%	10.4%	12.7%	11.0%	10.3%	9.6%	9.8%	10.0%	10.5%	9.8%	8.3%	8.4%	9.6%	11.7%	9.6%	9.0%	9.3%	9.7%
Median	11.0%	12.3%	11.4%	12.5%	11.4%	11.8%	12.1%	12.0%	13.8%	12.3%	11.0%	10.9%	9.3%	10.0%	9.4%	9.7%	7.9%	8.4%	9.0%	12.0%	9.5%	8.3%	8.8%	9.3%
Avera Proxy Group																								
Ameren	12.7%	12.9%	13.7%	13.1%	12.5%	10.8%	12.7%	12.5%	14.5%	14.3%	10.8%	12.2%	10.0%	10.3%	8.5%	9.3%	8.8%	8.4%	8.5%	13.0%	9.6%	7.0%	7.0%	7.0%
American Electric Power	11.1%	11.9%	12.0%	12.4%	13.2%	13.5%	11.3%	10.5%	4.1%	12.9%	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	11.3%	11.7%	10.5%	10.5%	10.5%
CenterPoint Energy	11.8%	12.7%	12.7%	10.6%	11.6%	10.2%	11.0%	10.3%	15.4%	7.5%	9.6%	26.1%	13.1%	17.2%	29.1%	22.1%	22.6%	16.0%	15.0%	11.4%	19.0%	12.0%	12.0%	11.5%
Cleco	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.4%	8.2%	9.9%	9.7%	11.4%	13.4%	10.9%	10.0%	10.0%	9.5%
CMS Energy	8.9%	18.6%	17.3%	15.7%	14.4%	13.9%	11.1%	13.6%	12.4%	7.5%	-27.1%	-3.3%	7.2%	10.4%	6.2%	6.6%	12.1%	8.3%	11.8%	13.3%	3.6%	12.5%	12.5%	12.5%
Constellation Energy	9.4%	10.4%	10.6%	10.8%	9.6%	10.2%	10.5%	10.9%	11.2%	9.9%	9.8%	11.5%	12.4%	12.4%	14.2%	15.5%	2.1%	6.0%	3.9%	10.4%	9.8%	6.0%	5.5%	7.5%
DTE Energy	18.7%	15.3%	11.8%	13.0%	11.8%	11.9%	12.2%	12.7%	11.9%	7.6%	13.7%	9.7%	8.1%	10.2%	7.5%	7.7%	7.5%	8.7%	9.6%	12.7%	9.2%	9.0%	9.0%	9.0%
Edison International	13.4%	11.8%	11.5%	11.8%	11.2%	11.8%	12.7%	13.7%	-52.0%	14.9%	15.4%	15.8%	3.9%	17.4%	14.9%	13.4%	13.4%	10.9%	10.7%	6.1%	12.9%	8.0%	8.5%	8.0%
Great Plains Energy	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	14.2%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	11.8%	11.3%	5.5%	6.5%	7.5%
Hawaiian Electric Industries	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	5.9%	7.7%	11.0%	8.8%	8.0%	9.0%	10.5%
IDACORP	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	12.3%	7.8%	9.5%	9.0%	8.5%
Integrys Energy Group							18.1%	11.4%	12.1%	12.7%	11.6%	10.7%	14.4%	13.2%	10.3%	6.3%	3.8%	5.8%	8.6%	13.6%	9.4%	9.0%	9.0%	9.5%
ITC Holdings														14.8%	9.0%	13.1%	13.8%	13.3%	13.5%		12.9%	13.5%	14.5%	15.5%
Pepco Holdings	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	5.5%	6.5%	11.0%	7.9%	6.5%	6.0%	7.5%
PG&E Corp	13.6%	11.9%	13.9%	14.4%	10.4%	7.5%	8.9%	11.2%	-67.5%	30.1%	-22.1%	20.9%	13.8%	11.7%	13.2%	11.9%	12.8%	11.3%	10.0%	5.4%	9.3%	9.0%	11.0%	11.5%
Pinnacle West Capital	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	11.5%	8.0%	8.0%	9.0%	9.0%
Portland General	12.9%	12.0%	11.3%	13.4%	13.9%										5.9%	11.5%	6.5%	6.2%	8.0%	12.7%	7.6%	9.0%	9.0%	9.0%
PPL Corp	13.1%	13.2%	10.6%	12.1%	12.4%	11.7%	15.8%	17.9%	26.1%	27.0%	23.6%	23.1%	18.3%	16.8%	18.4%	18.7%	17.2%	8.5%	14.5%	16.0%	17.7%	12.0%	12.5%	11.5%
TECO Energy	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	10.4%	11.4%	15.6%	10.6%	12.5%	13.5%	13.0%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	6.7%	8.4%	7.5%	8.5%	10.0%
Wisconsin Energy	11.4%	11.8%	10.5%	13.0%	11.5%	3.2%	10.1%	11.3%	6.4%	10.6%	12.8%	11.8%	9.0%	11.6%	11.1%	11.1%	11.0%	10.8%	12.2%	10.0%	11.3%	13.0%	13.0%	14.0%
Average	12.1%	12.6%	12.0%	12.6%	12.1%	10.5%	12.0%	11.8%	4.9%	13.1%	8.2%	11.6%	10.7%	11.9%	11.5%	11.1%	9.8%	8.8%	9.9%	11.4%	10.4%	9.4%	9.8%	10.1%
Median	11.4%	12.0%	11.5%	12.4%	11.7%	11.7%	11.5%	11.7%	12.1%	12.7%	11.6%	11.5%	9.3%	11.7%	9.8%	10.6%	8.8%	8.5%	9.6%	11.9%	10.2%	9.0%	9.0%	9.5%

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	1992-2001 Average	2002-2010 Average
Proxy Group																					
Ameren	169%	188%	160%	170%	175%	174%	180%	167%	163%	173%	163%	162%	161%	172%	164%	159%	122%	83%	81%	172%	141%
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	94%	106%	163%	109%
Cleco Corp.	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	181%	152%
Great Plains Energy	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	178%	155%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	147%	160%
OGE Energy	165%	159%	147%	166%	171%	198%	222%	183%	154%	166%	147%	153%	178%	189%	204%	196%	145%	139%	180%	173%	170%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	90%	113%	136%	117%
TECO Energy	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	131%	164%	235%	169%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	127%	136%	133%	145%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	91%	111%	118%	115%
Average	162%	171%	147%	155%	160%	168%	182%	157%	174%	160%	131%	134%	159%	167%	168%	163%	133%	107%	126%	164%	143%
Median	163%	161%	144%	156%	158%	167%	180%	160%	159%	160%	141%	124%	168%	175%	169%	164%	127%	104%	125%	161%	144%
Avera Proxy Group																					
Ameren	169%	188%	160%	170%	175%	174%	180%	167%	163%	173%	163%	162%	161%	172%	164%	159%	122%	83%	81%	172%	141%
American Electric Power	143%	159%	143%	156%	176%	187%	191%	154%	147%	179%	138%	124%	155%	165%	161%	190%	145%	112%	118%	164%	145%
CenterPoint Energy	167%	183%	148%	140%	140%	129%	168%	163%	182%	179%	116%	142%	236%	329%	312%	330%	224%	187%	158%	160%	226%
Cleco	177%	175%	156%	162%	168%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	181%	152%
CMS Energy	168%	223%	185%	182%	181%	200%	221%	189%	119%	152%	137%	80%	90%	125%	142%	177%	127%	117%	148%	182%	127%
Constellation Energy	128%	140%	127%	136%	142%	152%	164%	141%	193%	160%	110%	135%	157%	194%	227%	312%	264%	87%	80%	148%	174%
DTE Energy	162%	154%	120%	130%	137%	126%	165%	145%	126%	142%	145%	142%	132%	140%	134%	143%	101%	91%	116%	141%	127%
Edison International	167%	172%	122%	116%	120%	158%	192%	173%	197%	128%	117%	108%	153%	205%	194%	208%	149%	101%	111%	155%	150%
Great Plains Energy	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	178%	155%
Hawaiian Electric Industries	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	147%	160%
IDACORP	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	94%	113%	168%	119%
Integrys Energy Group							346%	153%	153%	157%	154%	162%	166%	174%	155%	139%	109%	82%	126%	202%	141%
ITC Holdings														394%	321%	376%	290%	219%	210%		302%
Pepco Holdings	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	92%	150%	111%
PG&E Corp	168%	175%	142%	134%	115%	123%	152%	135%	179%	136%	149%	203%	196%	179%	201%	203%	144%	149%	148%	146%	175%
Pinnacle West Capital	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	90%	113%	136%	117%
Portland General	115%	125%	112%	140%	199%										153%	140%	101%	83%	97%	138%	115%
PPL Corp	170%	181%	144%	138%	143%	128%	176%	232%	257%	352%	253%	239%	230%	259%	261%	316%	288%	209%	180%	192%	248%
TECO Energy	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	131%	164%	235%	169%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	91%	111%	118%	115%
Wisconsin Energy	178%	177%	160%	172%	169%	154%	185%	152%	119%	126%	129%	147%	156%	168%	182%	179%	153%	147%	171%	159%	159%
Average	161%	171%	144%	151%	159%	161%	188%	161%	165%	168%	139%	141%	162%	191%	185%	195%	154%	117%	129%	164%	165%
Median	167%	172%	143%	140%	161%	153%	180%	158%	163%	157%	137%	135%	157%	176%	164%	173%	132%	101%	118%	159%	144%

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2010

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	188%
2010	14.2%	208%
Averages:		
1992-2001	**14.7%**	**341%**
2002-2010	**12.4%**	**258%**

Source: Standard & Poor's Analyst's Handbook, 2011 edition, page 1.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Proxy Group						
Ameren	3	0.80	B++	3.67	B	3.00
Avista Corp.	2	0.70	B++	3.67	A-	3.67
Cleco Corp.	2	0.65	B++	3.67	B	3.00
Great Plains Energy	3	0.75	B+	3.33	B	3.00
Hawaiian Electric Industries	3	0.70	B+	3.33	B	3.00
OGE Energy	2	0.75	A	4.00	A-	3.67
Pinnacle West Capital	2	0.70	B++	3.67	B	3.00
TECO Energy	3	0.85	B+	3.33	B	3.00
UIL Holdings	2	0.70	B++	3.67	B	3.00
Westar Energy	2	0.75	B++	3.67	B	3.00
Average	2.4	0.74	B+/B++	3.60	B/B+	3.13
Avera Proxy Group						
Ameren	3	0.80	B++	3.67	B	3.00
American Electric Power	3	0.70	B++	3.67	B	3.00
CenterPoint Energy	3	0.80	B	3.00	B	3.00
Cleco	2	0.65	B++	3.67	B	3.00
CMS Energy	3	0.75	B+	3.33	B	3.00
Constellation Energy	3	0.80	B+	3.33	B	3.00
DTE Energy	3	0.75	B+	3.33	B+	3.33
Edison International	3	0.80	B++	3.67	B	3.00
Great Plains Energy	3	0.75	B+	3.33	B	3.00
Hawaiian Electric Industries	3	0.70	B+	3.33	B	3.00
IDACORP	3	0.70	B+	3.33	B	3.00
Integrys Energy Group	2	0.90	B++	3.67	B	3.00
ITC Holdings	2	0.80	B++	3.67	NR	
Pepco Holdings	3	0.80	B	3.00	B	3.00
PG&E Corp	2	0.55	B++	3.67	B	3.00
Pinnacle West Capital	2	0.70	B++	3.67	B	3.00
Portland General	3	0.75	B+	3.33	NR	
PPL Corp	3	0.65	B++	3.67	A-	3.67
TECO Energy	3	0.85	B+	3.33	B	3.00
Westar Energy	2	0.75	B++	3.67	B	3.00
Wisconsin Energy	2	0.65	B++	3.67	A	4.00
Average	2.7	0.74	B+/B++	3.48	B+	3.11

SUMMARY OF RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Proxy Group	2.4	0.74	B+/B++	B/B+
Avera Proxy Group	2.7	0.74	B+/B++	B+
Pinnacle West Capital	2.0	0.70	B++	B

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

ARIZONA PUBLIC SERVICE COMPANY
RATING AGENCY RATIOS

ITEM	PERCENT	COST RATE	WEIGHTED COST	PRE-TAX COST	
Long-Term Debt	46.06%	6.38%	2.94%	2.94%	
Common Equity	53.94%	9.90%	5.34%	8.22%	(1)
TOTAL CAPITAL	100.00%		8.28%	11.15%	

(1) Post-tax weighted cost divided by .65 (composite tax factor)

Pre-tax coverage = 11.15%/(2.94%)
3.80 X

Standard & Poor's Utility Benchmark Ratios:

	BBB
Pre-tax coverage (X)	
Business Position:	
5	2.4 - 3.5 x
Total Debt to Total Capital (%)	
Business Position	
5	50 - 60 %

Note: Standard & Poor's no longer employs the pre-tax coverage ratios as one of its qualitative ratings criteria. The above-cited S&P benchmark ratios reflect the 1999 criteria reported by S&P.

ATTACHMENT 2

June 25, 2008

Arizona Public Service Co.

Primary Credit Analyst:
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Arizona Public Service Co.

Major Rating Factors

Corporate Credit Rating
BBB-/Stable/A-3

Strengths:

- A favorable power supply adjuster (PSA) that while capped at 4 mils per kilowatt-hour (kWh) is benched to projected power prices, which should minimize fuel and purchased power deferral balances going forward;
- Declining legacy deferral balances, reflecting the recovery through surcharges of past fuel and purchased power costs from retail ratepayers;
- An attractive service territory, which while currently weakened by a real estate cycle that is depressing new customer connections, nevertheless is expected to experience above-average growth over the long run;
- A balance power supply portfolio that is a mixture of coal, nuclear, and gas generation and purchases; due to a self-build moratorium in place until 2015, Arizona Public Service (APS) is expected to increasingly rely on gas-fired purchases, which underlines the importance of a strong PSA;
- Stabilized operations at Palo Verde, although the nuclear units remain under heightened Nuclear Regulatory Commission (NRC) scrutiny; APS operates the plant and owns a 29.1% share of the plant; and
- A manageable maturity schedule for both the parent and the utility until 2011 when about $578 million is due on a consolidated basis.

Weaknesses:

- The consolidated financial profile of the company is unlikely to meaningfully improve for the foreseeable future due to APS' heavy capital investment, coupled with a lagged regulatory process in Arizona;
- Continued tension in the relationship between APS and the Arizona Corporation Commission (ACC), which is particularly unfavorable for credit quality due to the company's ongoing need for rate relief;
- APS' re-filing of its 2008 general rate case based on a revised test year is expected to delay rate relief past the summer of 2009, which will, all else equal, weaken cash flow measures;
- Consolidated free operating cash flows are expected to be negative through at least 2010, based on the company's capital spending program; and
- SunCor's near-term prospects to make distributions to its parent are limited, due a depressed real estate cycle, which has hit the southwest especially hard.

Rationale

Standard & Poor's Ratings Services today affirmed the 'BBB-' corporate credit rating assigned to Pinnacle West Capital Corporation (PWCC) and its utility, Arizona Public Service. The outlook is stable. The consolidated credit ratings of PWCC primarily reflect the operations of its largest subsidiary, APS, a regulated, electric utility serving about 1.1 million customers within its service territory, which spans roughly two-thirds of Arizona and includes about half of the Phoenix MSA. We view the business profile of PWCC and APS to be 'strong'. While the company continues to benefit from a number of favorable attributes including a good service territory, a reasonably balanced power supply portfolio and a good PSA. However, APS' continues to face significant regulatory challenges.

APS provided the company with about 92% of its consolidated net income in 2007. SunCor, PWCC's real estate development company, provided about 4%, but due to the significant real estate slowdown in the southwest, it is unlikely it will be a meaningful contributor of cash flows or income over the next several years. (Prior to the real estate downturn, our forecasts have conservatively limited earnings from this subsidiary due to the cyclic nature of its cash flows.) Other subsidiary operations include Pinnacle West Trading and Marketing, which contributed about 4% of consolidated net income in 2007. This subsidiary has since last year been minimizing trading operations. Its largest contract was serving all-requirements load for UNS Electric Inc., which ended in May 2008.

We view the financial profile of PWCC and APS to be 'aggressive', which reflects: year-end debt to total capitalization of 57% (adjusted for items such as power purchases and operating leases); heavy capital spending that is expected to drive negative free operating cash flow for the foreseeable future; cash flow weakness as a function of protracted rate cases; and, while modest, the presence of unregulated activities, which can be unpredictable in their earnings contributions.

Because the preponderance of cash flows for consolidated operations stems from APS, we expect financial performance will continue to be heavily dependent on regulatory outcomes. The conclusion of APS' last general rate case in June 2007 (filed in November 2005 and revised in early 2006) provided the company with mechanisms to recover legacy deferrals and speed the recovery of fuel costs going forward. This rate relief, in place for the last half of 2007, assisted the company in maintaining credit metrics roughly in line with past performance. Funds from operations (FFO) to total debt was about 16% at year-end, with FFO interest coverage around 4x. On a trailing 12-month basis the company's performance has been slightly above these levels, due in part to the federal tax stimulus package approved by the U.S. Congress earlier this year, which is expected to increase deferred taxes (which are added back to FFO and thus increase this total).

We expect APS to be in more or less continuous rate case mode for the next few years. Given APS' capital spending program, forecasted to be about $1.1 billion annually through 2010, the utility will need to file regular general rate cases to manage recovery of its investment. The use of a historical test year in Arizona, coupled with the fact that fully litigated rate cases take between 18 to 24 months to complete, is expected to result in no meaningful improvement in financial performance through 2009 and possibly beyond, depending on the timing and the outcome of the company's current case.

APS filed its current rate case in March 2008. ACC staff requested that the company revise its filing to reflect a test year ending Dec. 31, 2007 (as opposed to the originally filed version based on a Sept. 30, 2007, test year). The revised case has not been officially certified by the ACC, but certification is expected by July 2. Unlike the company's last rate case, in which $315 million of the $322 million of rate relief granted was for fuel and power-related costs, the majority of the current case is for nonfuel expenditures.

While the revised case increased the company's request to $278 million (about an 8.5% increase, excluding the company's request that customers be assessed about $53 million in impact fees), the re-filing means that is unlikely the ACC will reach an outcome in the case before October 2009, and because the majority of APS' sales occur in the summer months, the company's financial performance could weaken in 2009.

This month, the company requested that the ACC allow it to continue to collect a $0.004/kWh charge that it has been collecting in 2007 to recover legacy purchased power and fuel deferrals. Given that the portion of deferred costs associated with this surcharge is due to be paid by July or August, APS has asked that the ACC continue the charge, but authorize collection as an interim base rate increase, subject to refund as part of the resolution of its rate case, expected in fall 2009. (Last year, the ACC approved similar relief for Tucson Electric Power in its pending rate case settlement when it granted the southern Arizona utility the opportunity to continue to collect charges related to a competitive transition charge, or CTC, while its rate case is pending.) While retail customers would essentially see no rate increase because APS is asking to continue the surcharge as an interim increase, it is unclear what action the ACC will take. A vote could occur as early as late summer.

In 2008, we expect a procedural schedule to be established for the APS rate case, and greater clarity around the timing of an outcome will be available once this is issued. Of note is that three of the five commissioners are facing term limits and will no longer be on the ACC beginning in 2009. Commissioners are popularly elected and about a dozen candidates have announced they will run for the November election. As a result, a majority of the commissioners presiding now will not be on the commission when an APS rate case ruling is rendered. What this means for credit quality is unclear.

APS was successful earlier this year in receiving approval for a change in its line extension policies, which eliminates the free footage allowance that used to be available for customers. As a result, the portion of the company's capital expenditures associated with new line extensions will be offset with contributions in aid of construction (CIAC). This is favorable and year to date ended March 31, 2008, had added about $10 million in incremental cash flows to the company. Because it is booked under investing activities, cash flow metrics are not improved, but we recognize the significant benefit of APS receiving upfront cash from customers to meet a portion of its distribution capital investment plans. Future cash flows from customers in the form of CIAC will depend on the number of new meter sets, which are significantly off year to date due to the poor real estate market in Arizona and a slowing economy generally.

APS has a well-diversified power supply portfolio that in 2007 consisted of about 22% nuclear generation, 37% coal generation, approximately 18% owned gas generation, and the balance, about 23%, of purchases. We would expect the company's purchased power obligations to steadily climb due to the fact that APS is under a self build moratorium until 2015. APS will also need to meet relatively stringent renewable portfolio standards (RPS). It has in place a surcharge to pass through to customers the costs of RPS compliance.

Palo Verde performance has stabilized, and it has a plan in place to address NRC concerns. As of the first quarter of 2008, the combined capacity factors for all three Palo Verde units was 93%, as compared with 79% for 2007 (which reflects in part an extended planned outage to replace steam generators at unit 3) and 71% in 2006, which largely reflects unplanned outages at unit 1 related to excessive vibration that occurred when that unit exited its extended outage for refueling and replacement of steam generators. Palo Verde Unit 3 remains in the NRC's "multiple/repetitive degraded cornerstone" column of the NRC's Action matrix, which subjects all three Palo Verde units to enhanced NRC inspection regime. Preliminary work in support of this took place throughout the summer of 2007. In February, the NRC issued its inspection report, which determined the plant was operating safely but which also outlined an improvement plan for APS. In late March, APS in turn submitted to the NRC a final improvement plant addressing issues raised in the NRC inspection report. While the nuclear units appear to be on a path to improve operational performance and restore NRC confidence in the operational and safety standards at the plant, this will remain an area of concern until the NRC removes it degraded designation.

Short-term credit factors

APS and PWCC's short-term rating is 'A-3'. Liquidity is adequate. Pinnacle West has $18 million of cash and cash equivalents, and total credit facilities of nearly $1.4 billion, with approximately $943 million available as of March 31, 2008. In October 2007, APS received approval from ACC to increase its authorized short-term debt borrowing capacity by $500 million, and long-term debt borrowing capacity by $1 billion. This will help address the needs of its growing customer base, and the increasing requirement for natural gas and purchased power.

Pinnacle West had close to $185 million available under its $300 million unsecured revolving credit facility that expires in December 2010. APS had $682 million available under its two unsecured revolving credit facilities, $400 million of which expires in December 2010, and $500 million in September 2011. SunCor has two credit facilities expiring in October and December 2008 that total $170 million and approximately $76 million, respectively, available as of September 2007.

Discretionary cash flow is expected to be negative for 2008 due to APS' capital expenditure plans. Excluding the remarketing of APS' pollution control debt, neither PWCC nor APS has any significant debt obligations maturing until 2011.

Outlook

The stable outlook reflects our expectation that consolidated cash flow volatility has been tamped down by the ACC's approval of a stronger PSA that speeds the recovery of fuel costs, but consolidated financial performance will continue to be challenged by regulatory lag at APS, which could be moderated by APS' pending interim rate request. The stable outlook is premised on no meaningful adverse changes in the company's business risks and continued financial performance that is not significantly weaker than 2007 results. Equity issuances will be expected to balance the capital structure of the company as APS continues to invest heavily in infrastructure. Ratings could be lowered to speculative grade if the company is not able to overcome the challenge of ensuring timely recovery of its prudently incurred costs through rate increases approved by the ACC. Given these challenges, and that presented by NRC scrutiny of Palo Verde, we see little potential for positive movement in the ratings or outlook.

Rating Methodology

The ratings on PWCC and its subsidiaries are determined based on Standard & Poor's consolidated ratings methodology. The application of this approach reflects significant financial and operational inter-relationships among the rated entities and captures the relative contribution to business risk and cash flow of the operating segments. In the absence of meaningful regulatory measures that can restrict the flow of funds within the company, Standard & Poor's considers PWCC's consolidated financial profile, while still analyzing the financial profiles of the standalone entities, to be the best indicator of credit quality of the parent and its subsidiaries, including APS.

Accounting

PWCC reports its financial statements in accordance with U.S. GAAP. These statements received an unqualified opinion by PWCC's independent auditor, Deloitte and Touche LLC, in the most recent annual audited period.

The company benefits from the use of regulatory accounting SFAS 71 (accounting for the effects of certain types of regulation), under which some incurred costs or benefits that will probably be recovered or refunded in customer rates are deferred and recorded as regulatory assets or liabilities. As of Dec. 31, 2007, PWCC's consolidated balance sheet contained total regulatory assets and total regulatory liabilities of $625 million and $643 million respectively, reflecting assets expected to be recovered and liabilities expected to be settled in future rates.

We make several adjustments to PWCC's financial statements. In 1986, APS sold about 42% of Palo Verde Unit 2 as part of a sale-leaseback transaction. We treat these obligations as operating leases and in 2007 imputed an off-balance-sheet obligation of $432.18 million. We also impute $293 million for power purchase obligations in 2007, a number we expect to increase given APS' increasing power purchases. Reported ratios also reflect adjustments to impute debt for unfunded pension and postretirement benefit obligations of $329.72 million as of the end of 2007.

Table 1

Pinnacle West Capital Corp. -- Peer Comparison*

Industry Sector: Electric

	Pinnacle West Capital Corp.	Puget Energy Inc.	Avista Corp.	Unisource Energy Corp.	PNM Resources Inc.
Rating as of June 24, 2008	*BBB-/Stable/A-3*	*BBB-/Watch Neg/--*	*BBB-/Stable/A-3*	*-/-/-*	*BB-/Stable/B-2*
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	3,304.4	2,899.7	1,427.9	1,309.3	2,154.2
Net income from cont. oper.	264.1	166.1	52.3	57.9	82.8
Funds from operations (FFO)	683.7	442.5	186.2	283.6	281.5
Capital expenditures	778.6	726.5	194.5	225.1	339.1
Cash and short-term investments	93.2	30.1	20.6	113.1	70.4
Debt	4,419.9	3,343.9	1,368.8	1,838.8	2,684.7
Preferred stock	0.0	89.5	0.0	0.0	9.6
Equity	3,366.1	2,298.5	854.7	640.2	1,564.5
Debt and equity	7,786.0	5,642.4	2,223.5	2,479.0	4,249.3
Adjusted ratios					
EBIT interest coverage (x)	2.8	2.0	1.8	1.7	1.7
FFO int. cov. (X)	3.6	2.9	2.7	2.8	2.7
FFO/debt (%)	15.5	13.2	13.6	15.4	10.5
Discretionary cash flow/debt (%)	(8.2)	(13.4)	(1.7)	2.1	(5.7)
Net cash flow / capex (%)	62.2	46.9	81.0	113.0	65.2
Total debt/debt plus equity (%)	56.8	59.3	61.6	74.2	63.2
Return on common equity (%)	6.8	7.2	5.7	8.3	5.4
Common dividend payout ratio (un-adj.) (%)	75.5	60.4	54.7	50.4	72.9

*Fully adjusted (including postretirement obligations)

Table 2

Pinnacle West Capital Corp. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	2006	2005	2004	2003
Rating history	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB-/Stable/A-3	BBB/Negative/A-2	BBB/Stable/A-2
(Mil. $)					
Revenues	3,523.6	3,401.7	2,988.0	2,899.7	2,759.5
Net income from continuing operations	298.8	317 1	176 3	243.2	240.6
Funds from operations (FFO)	735.3	736.3	579.6	567.6	932.3
Capital expenditures	933 9	743.2	658.7	591.7	713.3
Cash and short-term investments	56 3	87 2	154.0	163.4	131 1
Debt	4,686.5	4,358.6	4,214 6	4,272 8	4,120 9
Preferred stock	0.0	0.0	0.0	0 0	0.0
Equity	3,531.6	3,446 1	3,120.5	2,653.7	2,510.0
Debt and equity	8,218.1	7,804.7	7,335.1	6,926.5	6,630.8
Adjusted ratios					
EBIT interest coverage (x)	2.7	3 0	2.6	2.6	2 2
FFO int. cov. (x)	3.7	3.8	3.3	3.2	4.2
FFO/debt (%)	15.7	16.9	13.8	13.3	22.6
Discretionary cash flow/debt (%)	(10.1)	(12.5)	(1.7)	2.6	1.0
Net cash flow / capex (%)	56.2	72.0	59.7	67.7	103.6
Debt/debt and equity (%)	57.0	55.8	57.5	61.7	62.1
Return on common equity (%)	7.3	8.2	4.8	7.7	7.1
Common dividend payout ratio (un-adj.) (%)	70.4	63.4	105.9	68.6	65.4

*Fully adjusted (including postretirement obligations)

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

	--Fiscal year ended Dec. 31, 2007--							
Pinnacle West Capital Corp. reported amounts								
	Debt	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Capital expenditures
Reported	3,631 6	992.7	992.7	619 3	189 6	649.6	649.6	941 6
Standard & Poor's adjustments								
Operating leases	432.2	79.0	27.7	27.7	27.7	51.3	51.3	15.4
Postretirement benefit obligations	329.7	12.8	12.8	12.8	--	8.7	8 7	--
Capitalized interest	--	--	--	--	23.1	(23.1)	(23.1)	(23.1)
Share-based compensation expense	--	--	6.0	--	--	--	--	--
Power purchase agreements	293.0	21.1	21.1	18.1	18.1	3.0	3.0	--

Table 3

Reconciliation Of Pinnacle West Capital Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*(cont.)

Reclassification of nonoperating income (expenses)	--	--	--	20.0	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	66.6	--
US decommissioning fund contributions	--	--	--	--	--	(20.7)	(20.7)	--
Total adjustments	1,054.9	117.8	67.6	78.6	68.9	19.2	85.8	(7.7)

Standard & Poor's adjusted amounts

	Debt	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Capital expenditures
Adjusted	4,686.5	1,105.5	1,060.2	697.8	258.4	668.8	735.3	933.9

*Pinnacle West Capital Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of June 25, 2008)*

Arizona Public Service Co.	
Corporate Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
21-Dec-2005	BBB-/Stable/A-3
01-Apr-2005	BBB/Stable/A-2
19-Mar-2004	BBB/Negative/A-2
Related Entities	
Pinnacle West Capital Corp.	
Issuer Credit Rating	BBB-/Stable/A-3
Commercial Paper	
Local Currency	A-3
Senior Unsecured	
Local Currency	BB+
PVNGS II Funding Corp. Inc.	
Issuer Credit Rating	BBB-/Stable/--
Senior Unsecured	
Local Currency	BBB-

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

The McGraw-Hill Companies

ATTACHMENT 3

Research Update:

Pinnacle West Capital Corp. And Arizona Public Service Co. Ratings Raised To 'BBB'

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Research Update:

Pinnacle West Capital Corp. And Arizona Public Service Co. Ratings Raised To 'BBB'

Overview

- We are raising our corporate credit rating to 'BBB' from 'BBB-' on holding company Pinnacle West Capital Corp. and electric utility subsidiary Arizona Public Service Co. At the same time, we are raising our unsecured issue rating on APS to 'BBB' from 'BBB-' and the short-term ratings on both entities to 'A-2' from 'A-3'.
- We are raising the ratings based on stronger credit metrics, bolstered by a reduction in debt, higher earnings, and periodic equity issuances; improved regulatory strategy; and prudent financial management during the rate freeze.
- Our outlook remains positive and reflects that we could raise the long-term credit rating another notch if regulatory dealings remain constructive and if the company continues to manage the balance sheet with equity issuances to support high capital spending.

Rating Action

On June 24, 2011, Standard & Poor's Ratings Services raised its corporate credit rating to 'BBB' from 'BBB-' on holding company Pinnacle West Capital Corp. (PWCC) and its electric utility subsidiary Arizona Public Service Co. (APS). At the same time, we raised the senior unsecured debt issue rating at APS to 'BBB' from 'BBB-' and the short-term ratings on both entities to 'A-2' from 'A-3'. The outlook is positive.

Rationale

The ratings reflect our view of improved consolidated financial performance, evidenced by stronger credit metrics, and progress in advancing the regulatory strategy of APS in Arizona. A reduction in debt leverage from equity issuances and debt reductions, coupled with stronger cash flows from higher earnings and tax benefits, increased FFO to debt. Prudent financial management during the current rate case stay-out period and the use of cost riders resulted in improved financial stability. A shift in company focus toward improving regulatory relationships in the past few years continues to benefit credit quality because the company has transitioned to slower customer growth. We could raise the ratings further if regulatory dealings remain constructive and the company continues to manage the balance sheet with equity issuances to offset high capital spending.

The 'BBB' corporate credit ratings on PWCC and APS reflect our view of regulated operations that provide almost all of the consolidated income and cash flow.

We view the business risk profile of PWCC and APS as excellent under our corporate risk profile matrix. The company benefits from a number of favorable business attributes, including the absence of competition in APS' regulated operations, a service territory with above-normal average growth rates and below-average unemployment prior to the current recession, a balanced power supply portfolio of coal, nuclear, and natural gas generation, and contract purchases backed by a power supply cost adjustment mechanism and a prudent hedging strategy that serve to ensure full recovery and dampen volatility. The business profile also reflects APS' success in managing regulatory risks in Arizona. The lack of material non-regulated operations, which typically increase business risk, adds further support to the profile.

The company has undergone a significant transition in recent years. High customer growth had necessitated that the company file regular general rate cases with the Arizona Corporation Commission (ACC) to recover its investments and operating costs, prior to the collapse of the housing market. The use of a historical test year in Arizona, coupled with an 18- to 24-month completion time for fully litigated rate cases, made it very difficult for APS to earn authorized returns. In recent years, regulatory lag has decreased and financial performance has improved because of interim rates, recovery of certain post-test-year costs, and an improved 11% authorized equity return in the previous general rate case. Slower growth and the addition of several rate riders that allow the company to true up certain costs outside of the general rate case process have mitigated the need to file large cases frequently. However, capital spending remains high due to replacements and renewable spending, necessitating a continued reliance on rate increases.

APS has a well-diversified power supply portfolio that supports the excellent business profile, consisting of the following energy sources in 2010: 36.6% coal, 26.8% nuclear, 24.3% purchases, and about 12.3% owned gas generation and other sources. The company is highly exposed to nuclear power availability and nuclear operations at Palo Verde Nuclear Generating Station, its largest single generating resource. Palo Verde has a history of mixed results tied to problems at the plant that appear to have been corrected. In April of 2011 operating licenses for all three reactor units were extended 20 years beyond the current 40-year licenses, allowing Unit 1 to operate through 2045, Unit 2 through 2046, and Unit 3 through 2047. We expect the company's purchased power obligations to steadily climb because solar energy remains a top public policy objective in Arizona and because significant portions will come from purchases. Construction is underway at Abengoa's 280-megawatt (MW) Solana concentrating solar plant after the U.S. Department of Energy approved a loan late last year. The loan and tax credits will help to blunt the impact of this resource on customer bills, which will represent a significant purchase commitment by APS. APS needs to meet Arizona renewable portfolio standards (RPS) of 10% by 2015 and 15% by 2025, with 30% of the total RPS coming from small-scale distributed resources by 2012. The company has a surcharge to collect the costs of RPS compliance, and this lessens the financial burden on the company.

APS is purchasing Southern California Edison's (SCE) 48% interest (739 MW) in Units 4 and 5 of the Four Corners Plant in New Mexico for $294 million. APS now owns a 15% interest in each unit. APS operates the plant and also owns 100% (560 MW) of Units 1 to 3. APS has announced that it will use the capacity to shut down Units 1 to 3, which are older and less efficient and which would be subject to significant environmental upgrades under rules proposed by the U.S. Environmental Protection Agency. The sale awaits regulatory approvals from the respective commissions and the Federal Energy Regulatory Commission. We view the transaction favorably from a credit perspective, assuming that it does not increase debt leverage and that the ACC approves all costs.

The aggressive financial risk profile of PWCC and APS reflects slightly higher leverage and adjusted funds from operations (FFO) to total debt that has averaged 20% over the past three years. We believe that rates will continue to support cash flows at the current rating level and possibly higher levels, rising as we expect new rates to take effect next year. Financial performance will continue to depend on the management of regulatory risk in Arizona and on the company's financing decisions regarding the usage of debt and equity as capital investments ramp up in 2012 and 2013. Average adjusted debt to total capital was around 60% at the end of 2009 (adjusted for items such as power purchase contracts, operating leases, and pension and other postretirement benefit obligations), but had improved to 55% by the end of 2010 due to the equity issuance and a reduction of debt.

We expect APS to maintain the ratings by funding its capital spending program with a balanced capital structure. The company had $748 million in capital expenditures in the 12 months ended Dec. 31, 2010, and plans to spend $960 million in 2011 and $1.33 billion in 2012 for renewable generation, environmental compliance, the Four Corners purchase, and system maintenance. A troubled real estate market in Arizona's historically high-growth service area has increased planning uncertainty, but slower growth has mitigated some spending pressure and rate lag, allowing the company to further its renewable investments and other infrastructure without the added burden of high customer growth contributing to rate lag pressure. Customer growth averaged 4% a year for 2005 through 2007, but has been nearly flat since. The resumption of growth levels witnessed during the previous housing boom could place renewed pressure on the company's financial profile, given high capital expenditure levels, but mechanisms and other factors that now exist would lessen the impact.

Liquidity

The short-term rating on APS and PWCC is 'A-2'. Consolidated liquidity is adequate under our corporate liquidity methodology, which categorizes liquidity under five standard descriptors. Under our analysis, projected sources of liquidity (mainly operating cash flow, available bank lines, and share issuances) exceed projected uses (mainly necessary capital expenditures, debt maturities, and common dividends), absent access to capital markets, by more than 1.2x for the upcoming 12 months. Liquidity may be pressured in 2011 or 2012 due to high capital expenditures that the company expects to incur, but we expect liquidity to remain adequate.

As of March 2011, PWCC had $183 million available under its $200 million unsecured revolving credit facility, expiring in 2013, and APS had $980 million available under its combined $1 billion unsecured revolving credit facilities. Half expires in 2013, and the remainder in 2015. SunCor is liquidating real estate assets to repay debt under its non-recourse secured credit facility. SunCor's liquidity and debt are not a factor in PWCC's or APS' overall liquidity position. The company's long-term debt maturities in 2011 total about $575 million.

Outlook

The positive outlook reflects our view that we could raise the long-term credit rating another notch if regulatory dealings remain constructive and if the company continues to manage the balance sheet with equity issuances that offset high capital spending in the next 18 months. APS' progress in managing its regulatory agenda in Arizona provides a platform for higher ratings contingent on financial prudence in containing costs and financing capital investments. Specifically, we may raise the ratings one notch if the company demonstrates sustained financial performance above our forecast levels of adjusted FFO to debt of 20% and adjusted debt to capital of 55%. Minimizing rate lag and earning close to authorized equity returns would help achieve such financial metrics. We will likely leave the rating the same if the company does not demonstrate continued financial improvement or the ability to further its regulatory agenda.

Related Criteria And Research

- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Assessing U.S. Utility Regulatory Environments, Nov. 7, 2007
- 2008 Corporate Criteria: Analytical Methodology, April 15, 2008

Ratings List

Upgraded

Pinnacle West Capital Corp.		
Arizona Public Service Co.		
Corporate credit rtg	BBB/Positive/A-2	BBB-/Positive/A-3
Commercial paper	A-2	A-3
Arizona Public Service Co.		
Senior unsecured	BBB	BBB-

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

ATTACHMENT 4

MOODY'S
INVESTORS SERVICE

Credit Opinion: Arizona Public Service Company

Global Credit Research - 25 Feb 2011

Phoenix, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa2
Sr Unsec Bank Credit Facility	Baa2
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2
Parent: Pinnacle West Capital Corporation	
Outlook	Stable
Issuer Rating	Baa3
Sr Unsec Bank Credit Facility	Baa3
Senior Unsecured Shelf	(P)Baa3
Subordinate Shelf	(P)Ba1
Preferred Shelf	(P)Ba2
Commercial Paper	P-3

Contacts

Analyst	Phone
Laura Schumacher/New York	212.553.3853
William L. Hess/New York	212.553.3837

Key Indicators

Arizona Public Service Company

ACTUALS	2010	2009	2008	2007
(CFO Pre-W/C + Interest) / Interest Expense [1][2]	4.8x	5.4x	5.0x	4.2x
(CFO Pre-W/C) / Debt [2]	24.5%	26.4%	22.8%	18.3%
(CFO Pre-W/C - Dividends) / Debt [2]	19.9%	22.1%	18.8%	14.0%
Debt / Book Capitalization	42.1%	45.4%	47.2%	45.9%

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items [2] Changes in margin and collateral accounts are excluded from CFO Pre-W/C

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Predominantly regulated operations

Regulatory supportiveness increasing, though lag persists

Low growth in service territory

Stronger financial metrics offset weaker regulatory environment

Corporate Profile

Arizona Public Service (APS: Baa2 senior unsecured, stable) is a vertically integrated electric utility that provides electric service to most of the state of Arizona with the major exceptions of about one-half of the Phoenix metropolitan area and the Tucson metropolitan area. APS is the primary subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, stable), a holding company that through its other subsidiaries sells energy related services. In 2010, Pinnacle completed the divestitures of much of its remaining non-regulated businesses.

DETAILED RATING CONSIDERATIONS

Regulatory supportiveness showing signs of improving, though process still lengthy and lag persists

APS' operations are regulated by the Arizona Corporation Commission (ACC), an elected commission that has tended to render its decisions after prolonged consideration. As a result, APS' ability to earn reasonable returns has been limited due to significant regulatory lag. APS has generally been awarded relatively reasonable ROEs and equity ratios, including an ROE of 11% and an equity ratio of 53.8% as part of its $207.5 million net base rate increase in the ACC's December 2009 order (75% of APS' request).

Historically, the ACC has taken a year and a half to two years to render decisions in APS' rate cases including its December 2009 order. Generally the length of time required by the rate decision process coupled with the use of a historic test year means that rates may reflect a rate base that is more than two years old. On February 1, 2011, APS filed a notice with the ACC that it intends to file a rate case on June, 1, 2011 using a year-end 2010 test year and will request new rates be in effect by July 1, 2012. This planned 13-month timeline was mentioned in the ACC's December 2009 order and would be significantly shorter than historic rate case timelines. Also as part of the order, APS is prohibited from filing another rate case until June 2013.

The significant regulatory lag and uncertain timing of rate case resolutions causes APS to map to a factor in the Ba range for its Regulatory Framework within Moody's Rating Methodology for Regulated Electric and Gas Utilities (the Methodology) which is below the Baa average for the regulated utility industry in the U.S.

Improved cost recovery

Although regulatory lag continues, APS utilizes several mechanisms that allow its rates to be adjusted outside of a general rate case. Moody's generally views these mechanisms as being supportive of credit quality as they tend to result in a more timely recovery of costs. APS' rates are adjusted annually to recover 90% of the difference between its costs for fuel and purchased power and the amounts included in base rates, limiting APS' exposure to volatile power and gas prices. The fuel recovery factor includes a forward estimate of power costs, which further helps to limit cost deferrals.

APS also has adjustment mechanisms that allow the utility to recover its costs for renewable energy, efficiency and demand side management programs. Transmission costs are recovered through a transmission cost adjustor which resets annually based on changes in APS' Federal Energy Regulatory Commission approved formula-based tariffs. APS is also currently able to recover its costs for new customer hookups via line extension payments from customers.

In December 2010, the ACC issued a policy statement supporting decoupling rate structures implemented through rate cases over a three year evaluation period. We generally view decoupling mechanisms as supportive to credit quality as they are intended to improve a utility's fixed cost recovery. No Arizona utilities currently have a decoupling mechanism; implementation is intended to occur during the next rate case process.

Due to APS' adequate ability to recover most non-base costs, APS maps to a factor in the Baa range for Factor 2: Ability to Recover Costs and Earn Returns within the Methodology.

Low customer growth in service territory

APS' service territory incorporates a majority of Arizona including significant parts of metropolitan Phoenix. As such, within the framework of the Methodology, for Factor 3: Diversification - Market Position, APS maps to a factor in the Baa range. Customer growth is expected to be 1-1.5% over the near-term.

Reasonably diverse generation capacity

APS has a fairly diverse, low-cost generation fleet including 1,747 MW of coal capacity and 1,146 MW of nuclear capacity which in 2010 provided approximately 37% and 27%, respectively, of its total energy needs. In November 2010, as part of a plan to comply with the EPA's BART ruling, APS announced it had agreed to acquire an additional 740 MW of capacity at Units 4 and 5 of the Four Corners coal plant from Southern California Edison and shutdown 560 MW of capacity at Units 1-3. The transaction is expected to close by year-end 2012. Pollution control equipment is expected to be installed on Units 4 and 5 to get the plant in compliance with the EPA's BART determination. This acquisition will moderately increase coal's contribution to APS' fuel mix but it does provide a low-cost fuel option and it will reduce emissions in the region. Within the framework of the Methodology, APS maps to a factor within the Baa range for Factor 3: Diversification - Generation and Fuel.

Financial Metrics

Since 2008, APS' key financial metrics have improved to levels which map to a low A factor, reflecting improved cost control, cost recovery mechanisms and moderating capital expenditures. Over the near-term, APS' credit metrics could remain comparable to 2010 levels due to the benefits of bonus depreciation assuming adequate regulatory treatment. In general, Moody's looks for APS to have financial metrics that are stronger than comparably rated utility operating companies operating in regulatory environments that are more supportive of credit quality.

Liquidity Profile

APS' cash flows and credit facilities generally are a stable source of liquidity. In 2010, APS' cash from operations covered 76% of its $732 million of capital expenditures and $182 million of dividends to Pinnacle. The shortfall was funded by an equity contribution from the parent. Capital expenditures are expected to be in the range of $1 - 1.3 billion annually over the near-term and financed with a combination of internal and external sources including periodic equity injections from Pinnacle. As part of APS' last rate case, Pinnacle is required to infuse $700 million of equity by December 2014; Pinnacle infused $253 million in proceeds from the issuance of new equity in 2010.

In 2010, APS increased its dividend modestly to Pinnacle. Moody's expects APS' future dividends to increase somewhat, but generally to remain in line with its current payout ratio of 70 to 75%.

APS' short-term liquidity sources include a commercial paper program sized at $250 million. The program is currently supported by two committed lines of credit totaling $1 billion consisting of a $500 million line that expires February 2013 and a $500 million line that expires February 2015. The facility expiring in 2015 replaces the a $489 million facility which was set to mature September 2011. As of December 31, 2010, APS had $20 million of letters of credit outstanding, no borrowings under its credit facilities and $100 million of cash on hand. APS also has approximately $44 million of variable rate pollution control bonds (PCB's) supported by letters of credit; of which, $26 million expire September 2011 and the remainder expire in 2013.

APS' credit agreements both have one financial covenant that requires the ratio of debt to total capitalization not exceed 65%. As of December 31, 2010, APS' debt to total capitalization ratio, calculated in accordance with the credit documents, was approximately 46%. The credit agreements do not require a material adverse change (MAC) representation for revolver borrowings. No rating triggers exist in any APS credit facilities though interest costs may increase under various financing agreements if a downgrade occurs. In addition to the letters of credit supporting the PCB's expiring September 2011, APS has $400 million of unsecured notes due October 2011 and $375 million of unsecured notes due March 2012.

The rating assumes APS will continue to prudently manage its liquidity. Within the framework of the Methodology, APS maps to a factor within the Baa range for Factor 4 - Liquidity.

Rating Outlook

The stable outlook reflects APS' predominately regulated cash flows and Moody's view that its credit metrics are likely to be sustainable at levels appropriate for the current ratings. The outlook assumes APS will be reasonably successful in managing its regulatory relationships and that capital expenditures will be financed in a balanced manner with a goal of maintaining or improving APS' current position of financial strength.

What Could Change the Rating - Up

APS' rating is not likely to be revised upward in the near-to-medium term. Longer term, an upgrade could be possible if there is consistent supportive regulatory treatment resulting in material, timely rate increases, or if there are material reductions in costs or leverage such that Moody's could anticipate key financial ratios improving significantly from their current levels, if for example, a ratio of CFO pre -WC / debt could be maintained in the mid-twenty percent range, there could be upward pressure on the rating.

What Could Change the Rating - Down

A downgrade could result if regulatory lag for capital spending becomes more pronounced, or if Palo Verde experiences an extended outage and APS is unable to recover higher maintenance and purchased power costs in a timely manner. A downgrade could result if Moody's expects a sustained weakening of financial metrics, if for example, the ratio of CFO pre -WC / debt would remain in the mid-teens for an extended period.

Rating Factors

Arizona Public Service Company

Regulated Electric and Gas Utilities Industry [1][2]	Current FYE 2010		Moody's 12-18 Month Forward View As of February 24, 2011	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework		Ba		Ba
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		Baa		Baa
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.1x	A	4.6x-4.9x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	24.6%	A	22-25%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	20.3%	A	17-21%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	44.9%	A	40-45%	A
Rating:				
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

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EXHIBIT
S-4

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

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SCHEDULES

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

My testimony reviews the Arizona Public Service Company's ("Company") proposed Efficiency and Infrastructure Account ("EIA") mechanism. Staff recommends that the Arizona Corporation Commission should reject the Company's EIA proposal as it is very broad and addresses risks such as weather and economic conditions.

In recognition of the Company's energy efficiency and distributed generation requirements and plans, I developed a Lost Fixed Cost Revenue ("LFCR") mechanism that is related to the Company's plans and performance. This mechanism, built upon the Company's disaggregated costs, recognizes that many of the Company's costs are not impacted by energy efficiency and distributed generation measures. The LFCR mechanism provides an appropriate adjustment based on the Company's energy efficiency and distributed generation performance.

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Attachment HS-1) before the following regulatory bodies.

- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio

- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Arizona Corporation Commission Utilities Division Staff ("Staff").

Q. What is the purpose of your testimony?

A. My testimony analyzes decoupling proposal of the Arizona Public Service Company ("Company").

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should reject the Company's decoupling proposal.
- The Commission should allow the Company to receive the "lost fixed cost revenue" only for distribution service as modified to reflect the stability of demand charges and any excess basic service charge ("BSC") revenues.

Q. What is revenue decoupling?

A. Decoupling is the term used to define a rate design that is designed to disconnect a utility's earnings or revenue from sales of energy or commodity. Decoupled rates can be designed to eliminate or reduce the utility's disincentive to encourage energy conservation, impacts of the business cycle and/or the effects of weather.

Q. Have you reviewed specific decoupled rate design proposals in other jurisdictions?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I am also assisting in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity.

Q. When a regulatory commission implements a decoupling proposal, is there a compensating benefit to customers?

A. When certain forms of decoupling are implemented customers subject to decoupling usually see at least two benefits. The utility's return on equity is reduced by 0 to 50 basis points to reflect the reduced business risk that is the result of a more stable revenue stream to the utility. The second benefit that commonly precedes or occurs simultaneously with a decoupling proposal is an aggressive utility sponsored or supported energy efficiency program to assist customers within the rate class to reduce their energy consumption and energy costs.

Q. Please describe the Company's decoupling proposal.

A. The Company's proposal is to establish an Efficiency and Infrastructure Account ("EIA") mechanism[1] that is focused on recovering fixed revenue per customer[2] on an annual basis.[3] The proposed EIA would exclude fuel and transmission charges because those areas are already subject to an adjustment mechanism or annual formula.[4] The EIA is

[1] Snook Direct 1:25
[2] Snook Direct 14:8 and Snook Direct Attachment LRS-1, page 2
[3] Snook Direct 15:7
[4] Snook Direct 15:19

proposed to include all customer classes except for street lighting, unmetered accounts and merchant generation station power.[5] For calculation purposes the EIA proposal uses two classes, residential and the applicable remaining non-residential customers, which I call "super" classes for identification.

The calculation of any overrecovery or shortfall is based on the Allowed Fixed Cost Revenue per Customer ($/customer-year) (calculated at the close of a rate case). That rate is multiplied by the average annual number of active meters to develop the Allowed Fixed Cost Recovery per Class ($)[6].

To determine the Actual Recovery of Fixed Costs per Class the EIA proposal then switches to a calculation that multiplies the Actual Annual Sales (kWh) times the Allowed Fixed Cost Revenue per Customer Rate per Class ($/kWh).[7] This calculation is made individually for each of the two "super" classes. The EIA proposal aggregates all underrecovery or overrecovery (from the two "super" classes) on an annual basis and recovers or repays those sums over the following twelve-month period beginning March 1st. The process would lump together all amounts from the two "super" classes and recover/repay the amount from all classes covered by the EIA on an equal percentage of total bill basis.[8]

In the event of overrecovery there would be no cap on the repayments. If underrecovery occurs, the repayment cap would be 3 percent[9] with the remaining balance plus interest carried to the next period.[10]

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[5] Snook Direct 17:6
[6] Snook Direct Attachment LRS-1, page 2, Item 3
[7] This value is also calculated at the completion of a rate case based on Test Year data. Snook Direct Attachment LRS-1, page 2, Item 2
[8] Snook Direct 19:11
[9] Snook Direct 21:11

Q. Is the switch from revenue per customer to revenue per kWh a flaw within the Company's EIA proposal?

A. From the Company's standpoint there is no flaw. The switch in basis provides the Company with recovery of lost fixed costs that occur from its energy efficiency program along with any changes in sales due to weather, economic conditions and/or other events. The methodology proposed transfers the Company's existing business risks due to weather and economic conditions to its customers.

Q. The Company describes its decoupling proposal as "modernizing" its rate structure. Is this accurate?

A. No. The Company is not proposing to significantly change its rate structure. For example it is not proposing to use any of the capabilities of its investment in advanced metering infrastructure ("AMI") to measure demand and apply a new distribution rate form to additional customers, instead its EIA proposal is a band-aid.

Q. What elements of the Company's revenue stream would be covered by the Company's revenue decoupling proposal?

A. Using the breakdown of costs from a Staff data request,[11] the Company is proposing to decouple the following cost areas:

- Production Demand
- Regulatory Assets
- Distribution
- Customer Management
  - Customer accounts and sales

[10] Snook Direct Attachment LRS-1, page 3, Item 4
[11] APS Response to Staff Data Request 3.27

- Metering
- Billing
- Meter Reading
- System Benefits[12]

Q. What elements of the Company's revenue stream would not be covered by the Company's decoupling proposal?

A. The Company is proposing not to decouple the following cost areas because they are already subject to adjustment mechanisms[13]:

- Energy
- Transmission

Q. What risks would be shifted from the Company to customers under the Company's revenue decoupling proposal?

A. The Company's EIA proposal compares the revenue per customer from the test year to actual annual energy sales times the test year rate. Any deviation from Test Year per customer sales is recaptured or repaid. This mechanism does not differentiate between changes in sales due to weather, economic activity or conservation. Therefore, the Company's proposal shifts all of these risks to its customers.

[12] APS Response to Staff Data Request 10.1
[13] Snook Direct 15:18

Q. Does the Company's cost of capital witness William Avera analyze the stability of the Company's revenue stream?

A. My review of that testimony did not find any analysis except for a discussion of attrition. He discusses mechanisms that shift away from volumetric recovery of fixed costs "preclude the prospects of greater earnings due to higher consumption."[14]

Q. Does the Company offer an adjustment in its return on equity to reflect its proposal to shift weather and economic risk to customers?

A. The Company witness Avera opines, "... there is certainly no evidence to suggest that these provisions would justify any adjustment to the ROE range determined earlier."[15]

Q. Can revenue decoupling aggravate the impact of adverse weather or economic conditions?

A. One year after a cool summer, the customer would receive a rate increase to recapture the Company's revenue shortfall. If a cool summer is then followed by a hot summer, the Company's proposed EIA would pancake the cost recovery on top of consumption increased by weather and increase the costs above what customers would have expected, thus creating a real detriment. A similar situation would occur during a multi-year economic recession.

Q. Is there any mechanism within the Company's decoupling proposal to adjust for increasing productivity by the Company over time?

A. No. The EIA proposal fixes all elements of the calculation based on the rate case Test Year. In this case that would be calendar 2010. As the Company increases its productivity the EIA would not change. For example, as the Company continued its

[14] Avera Direct 75:20
[15] Avera Direct 76:8

rollout of AMI throughout its service territory in 2012 and 2013 and changed its processes[16] to reduce its customer service and metering costs the EIA cost recovery component would not change and customers would see no productivity benefits.

Q. What areas of the Company's revenue do not require revenue decoupling?

A. Based on my analysis the following cost areas do not require decoupling protection in whole or in part:

- Production Demand
- Energy
- Regulatory Assets
- Transmission
- Distribution (partial)
- Customer Management
  - Customer Accounts and Sales
  - Metering
  - Billing
  - Meter Reading
- System Benefits

Q. What is the Company's forecast for sales?

A. The intent of decoupling is to hold the Company's recovery of fixed costs harmless from sales decreases due to the EE program. The Company's Load Forecast does not show a consistent decline in total sales to retail customers, but an increasing trend.

[16] APS Data Response to Staff 20.5

Year	Retail Sales (MWh)[17]
2011	28,202,200
2012	28,185,608
2013	28,405,734
2014	28,996,045
2015	29,541,216

The output of the Company's generating system is fungible. The generating system is not affected if energy is delivered to a new customer, an existing customer using slightly less energy, non-AZCC jurisdictional customers or sold off-system. Therefore, the Company has many opportunities to sell the output of its generating system and it is planning to do just that as its forecast demonstrates.

Q. Why is decoupling not necessary for Production Demand?

A. As I have demonstrated above, the Company does not forecast any decrease in long-term sales and thus the fungible output of the generating system will be sold to its retail customers per its forecast. In the event that the forecast is wrong the Company has other opportunities to sell the marginal output of its generating system.

Q. Did you explore this issue with the Company?

A. This question was raised during the Company's Technical Conference and a subsequent offline conference. The Company's informal response[18] offers the rationale to include production costs because "The question assumes fixed production costs remain constant and therefore do not increase over time. ... Whether these specific fixed costs increase proportionately with customer growth is another question ..."

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[17] APS Data Response to Staff 3.11 APS 14607 (Total Sales less Resale)
[18] Informal Response 1.4

Based on this response, the Company is proposing to apply its decoupling mechanism to production fixed costs in an attempt to derive additional revenue (as the annual number of customers increases) to offset expected capital additions to its current production plant.

The Company's position describes how it has created a revenue raising mechanism unrelated to capital additions and not offset by its concurrent ERA proposal. If the Company's rationale were accepted along with the proposed ERA then double compensation might occur. Therefore, I reject the Company's proposal to decouple production fixed costs.

Q. Why is decoupling not necessary for Regulatory Assets?

A. Regulatory Assets are allocated consistent with Production Demand and Energy and should be treated in the same manner for the same reasons.[19]

Q. Is decoupling needed for distribution revenue?

A. Distribution costs are not as fungible and distribution assets cannot serve other customers within the short term. Therefore a reduction in per customer sales may result in a shortfall in revenues to cover fixed costs. Decoupling is needed to recapture the portion of distribution costs that are collected on a volumetric (per kWh basis). Many of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

For some rate schedules, the Company is proposing to include within the Basic Service Charge ("BSC") a portion of its distribution costs (transformation).[20] If this proposal is accepted then there would be no need to decouple that portion of distribution costs.

[19] ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010, Sheet Cost of Service, Rows 74, 101, 123 and 124

Q. Why is decoupling not necessary for the existing Basic Service Charges?

A. As a customer takes advantage of energy efficiency or distributed generation the BSC is collected (on a per day basis) regardless of usage. Therefore, there is no need to decouple the BSC revenue.

Q. Why is decoupling not necessary for the existing System Benefits charges?

A. The System Benefits charge has generally remained fixed between rate cases, and the Company has not addressed why this precedent should be changed.

Q. Has the Company provided a long-term plan to modernize its rate structure?

A. The Company is proposing a number of modifications to individual rate schedules along with the elimination of some schedules that are used by few customers. However, in light of its installation of AMI, I am surprised that the Company has not presented a rate research plan to determine how the more detailed metering information can be used.

Q. Is the Company subject to an energy efficiency goal?

A. The rules[21] (the "Rules") set cumulative (and incremental) savings (based on prior year sales) as follows:

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[20] APS Response to Staff Data Request 3.27 APS 14583

[21] Arizona Administrative Code R14-2-2401, et seq (effective January 1, 2011)

Year	Cumulative Savings %[22]	Incremental Savings %	Prorated Incremental Savings %	Prorated Cumulative Savings %
2011	1.25	1.25	Not applicable	Not applicable
2012	3.00	1.75	0.875	0.875
2013	5.00	2.00	2.00	2.875
2014	7.25	2.25	2.25	5.125
2015	9.50	2.25	2.25	7.375

Q. Is energy efficiency cost effective for customers?

A. Yes. The analyses explored during the decoupling workshop proceedings forecast cost savings for customers as a result of a long-term energy efficiency program.

Q. Has the Company developed an energy efficiency plan?

A. Yes. The Company has proposed its 2012 Revised Demand Side Management Implementation Plan ("Plan"). The Plan is designed to meet the 2012 goal of a 1.75 percent reduction in sales amounting to 533,000 MWh.[23] The Plan provides estimates of the annual MWh saved for residential and non-residential customers.[24] The Plan provides a short description of the Measurement, Evaluation and Research ("MER") component including the contractor and budget.[25] The Company is requesting approval of its Plan before the end of 2011.

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[22] Arizona Administrative Code R14-2-2404, Table 1 (effective January 1, 2011)
[23] APS 2012 Revised Demand Side Management Implementation Plan, Docket No. E-01345A-11-0232, Table 2 (June 24, 2011)
[24] APS 2012 Revised Demand Side Management Implementation Plan, Docket No. E-01345A-11-0232, Table 7 (June 24, 2011)
[25] APS 2012 Revised Demand Side Management Implementation Plan Page 38

Q. Without some mechanism would the Company's Plan have a measureable impact on the Company's revenue?

A. Yes. The Rules require reductions in the Company's sales compared to each prior year. Absent a rate case adjustment if the Company meets those goals then a portion of the Company's distribution revenue could be impacted.

Q. What is the impact of APS' 2012 REST Plan?

A. This plan provides details of the Company's program to encourage distributed generation including "behind the meter" generation, which reduces the Company's sales to a customer that installs on-site generation.

Q. How should distributed generation be treated?

A. If the Company can document the "behind the meter" generation that offsets retail sales, as opposed to feeding into the distribution grid to serve other customers, the energy consumed on-site should be treated similarly to energy efficiency. The measurement protocol could include a production meter installed at the interface between the distributed generation and the customer's load (behind the meter). The readings from the production meter would be reduced by any excess energy delivered to the distribution grid.

Q. Have you developed an alternative that addresses the potential for lost distribution revenue as a result of the Company's Plan?

A. I recommend that a decoupling mechanism should be implemented based on lost fixed cost revenue ("LFCR").

Q. What risks would this LFCR mechanism cover?

A. The LFCR mechanism I recommend focuses specifically on the portion of the distribution revenue affected by the Company's compliance with its Plan.

Q. What about risks that arise from weather and changing economic conditions?

A. The Company presently accepts these risks and under the lost fixed cost revenue mechanism the risks remain with the Company; therefore, the Company's risk profile does not change.

Q. How would the lost fixed cost revenue mechanism operate?

A. I would adopt and/or modify certain aspects of the Company's decoupling proposal. These include:

- Use the fixed costs finally determined in this case's Test Year[26]
- Compute the lost fixed cost revenues on an annual basis
- Prorate (normalize) the lost fixed cost recovery revenues for partial year implementation[27]
- Perform the calculation in February and provide at least forty-five days for Staff to review the calculation[28]
- Implement the recovery of lost fixed costs in April for a twelve month period[29]
- Include the same customer classes[30]
- Compute the lost fixed cost revenues separately for residential and other customers (two "super" classes)[31]

[26] Snook Direct 21:23
[27] Snook Direct 21:24
[28] Snook Direct Attachment LRS-1 page 3 Filing and Procedural Deadlines
[29] Snook Direct 21:22
[30] Snook Direct 16:26
[31] Snook Direct Attachment LRS-1 pages 6 and 7

- Apply the recovery mechanism across the board to both of the "super" customer classes[32]
- Cap the annual adjustment for lost fixed cost revenue[33]
- Provide a Compliance Report annually[34]

The LFCR mechanism operates as follows:

- Derive the distribution lost fixed costs per kWh for the two "super" classes (see Attachment HS-2). In response to Staff Data Request 3.27 in APS 14600 the Company calculated the Distribution $/kWh (for example residential distribution is $ 0.0283 per kWh). After the conclusion of this case the Company can adjust the CCOSS to reflect the final decision and update APS 14600.

- Reduce the distribution lost fixed costs per kWh by 75 percent of the more stable distribution demand revenue from the Company's final revenue proof in this case similar to Work Paper CAM_WP13 for each of the two "super" classes (see Attachment HS-3 for the residential example). Although the demand revenue is subject to less impact from energy efficiency, I acknowledge that some energy efficiency efforts will impact demand revenue.

- Reduce the distribution lost fixed cost per kWh by the excess BSC (and adders) compared to the customer management costs as illustrated in Attachment HS-4.

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[32] Snook Direct 19:9 and Attachment LRS-1 page 8
[33] Snook Direct 20:26
[34] Snook Direct Attachment LRS-1 page 4 Compliance Reports

- Adopt the energy efficiency goal required by the rules for the previous calendar year. Multiplying the reduction goals by the prior year sales provides the initial estimate of the lost kWh for each of the two "super" classes. Also include the production measured from "behind the meter" distributed generation. Together this is the lost kWh.

- Multiplying the adjusted distribution lost fixed cost per kWh by the lost kWh for each of the two "super" classes computes the lost fixed cost revenue for the prior year. The LFCR are recovered in the same manner as the Company proposed in its EIA (see Attachment HS-5).

- Prorate the LFCR. The lost fixed cost revenues for 2012 would be prorated by the number of days the rates from this case were in effect in 2012. In future years, proration would be necessary to reflect base rate changes and the results of a new test year. The Company recognized this in its Informal Response 1.5.

In the following year the Company must make a retrospective adjustment to its LFCR by providing the results of its MER for the year. Results above the Rules would be capped at 25 percent with the excess available to be carried over to a following period, but still subject to the annual 25 percent excess limitation. Should the MER demonstrate that the Company did not achieve the savings as proposed by its Plan, the Company would refund the overrecovery with interest during the following period.

Q. What are the advantages of the LFCR mechanism?

A. The LFCR mechanism is based upon information readily available within the Company's Test Year filing, updated to reflect the results of this case. The mechanism recognizes the impact on the Company due to energy efficiency and distributed generation and recovers only the fixed costs that the Company actually loses (distribution) as opposed to all of the Company's non-variable costs. The Company continues to retain its weather and economic risks.

Q. What monitoring do you recommend for the LFCR mechanism?

A. Because any decoupling mechanism is new and untried, I recommend that the Company provide the Staff with quarterly reports (provided thirty days after the end of the quarter) that include an estimate of "saved" kWh and distributed generation and the expected value of the LFCR adjustment for that year. When the MER results are available for the prior year the Company should also apply that information to the calculation.

Q. Do you recommend a customer education plan for decoupling?

A. If either the LFCR or the EIA is approved for implementation the Company should submit a plan to Staff for customer education. In my experience this is an important element to make decoupling understandable to customers.

Q. In the unlikely event that the proposed EIA is approved should there be additional safeguards?

A. Yes, the EIA transfers a significant amount of risks such as weather and economic conditions from the Company to customers at a high per kilowatt hour rate and there could be detrimental effects.

Q. What additional safeguards should be included for the EIA?

A. The Staff should perform or have a consultant perform an annual review of the EIA mechanism, the Company's efforts to meet energy efficiency and distributed energy goals and the impact of the EIA on customers and the Company. The Company should fund this review.

Q. Should there be an earning surveillance mechanism for the Company if the EIA is implemented?

A. Yes. A decoupling mechanism is designed to correct disincentives, not enrich the Company. The implementation of the EIA can have unintended consequences and therefore earnings surveillance should be required.

Q. Do you have concerns about the existing, inactive but connected residential homes?

A. The present economic conditions have left the Company with "41,404 installed residential meters … currently inactive as of August 17, 2011."[35] These meters are installed on residential locations that have service drops, distribution facilities and transformation in place and are in ratebase. At the conclusion of this case, the distribution lost fixed cost per kWh rate for residential customers would include the costs of these assets. Reconnection of these inactive locations would incur incremental costs for meter reading, billing and customer accounting (all covered by the BSC collected) but no incremental cost for the distribution facilities already in place. This is one of the reasons for my recommendation for earnings surveillance.

Q. Should the EIA be time limited?

A. The ACC Policy Statement suggests, "In lieu of pilot adoption, an initial three-year review period should be utilized which allows for evaluation and redress of decoupling models and related issues."[36]

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[35] APS Data Response to Staff 6.28
[36] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures – paragraph 5

The Rules provide for annual reductions based on prior year sales that become cumulative and therefore the decoupling adjustment becomes larger each year. At the same time the 2010 Test Year costs become stale due to innovation and productivity improvements such as the distribution and customer management benefits that derive from AMI. The EIA shifts weather and economic risks to customers. Further the EIA rewards the Company with a substantially larger per kilowatt hour rate. Together the EIA could have a massive effect over time. Therefore the EIA should expire at the end of three years to avoid an adjustment factor on customers' bills that may optically seem larger than their perceived savings due to conservation. The Company would have the ability to petition the Commission to retain the EIA.

Q. **How long should decoupling (whether an EIA or a LFCR) remain in place?**

A. While the Company characterizes decoupling as modernizing the rate structure[37] it is merely a band-aid on an old rate structure. The Company does offer demand based rate structures for some rate classes and subclasses but with the advent of AMI it now has the technical capability to change from a volumetric focused rate structure.

Due to the complexity of the Company's tariff, frozen rate schedules and the advent of AMI, the Company should have offered a long-term process to modernize its tariff including consideration of higher demand charges in the short term and the examination of straight fixed variable ("SFV") or modified SFV rates for all or a portion (distribution) of its rate structure in the long term.

Changing the foundation of the rate structure requires research and an effective customer education plan to demonstrate to customers that they have the capability to reduce both

[37] Snook Direct 14:10

their demand and energy consumption and a corresponding rate structure that accurately charges for those elements.

Over time a true modern rate structure will obviate the need for a decoupling mechanism. If the rate research effort is executed appropriately the decoupling mechanism can be eliminated before its effects become too large to avoid a negative public perception.

Q. **Does this conclude your testimony?**

A. Yes.

Testimony - Howard Solganick

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)

Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.

Attachment HS-2

Net Lost Fixed Cost Revenue per Kilowatthour

Line No.		"Super" Residential	$/kWh	"Super" C & I Customers	$/kWh	General Service	$/kWh	Water Pumping	$/kWh
1	# of Customers (average annual bi	989,989		124,171		122,721		1,450	
2									
3	MWh sold (adjusted)	13,098,283		14,425,069		14,111,761		313,308	
4									
5	Distribution Costs	370,422,838	0.02828	192,480,168	0.01334	190,450,620	0.0135	2,029,549	0.0065
6									
7									
8	Adjustments								
9									
10	Delivery Demand Charge Adjustment ($/kWh)		-0.0014		0	**TO BE COMPUTED POST DECISION**			
11									
12	Excess BSC Adjustment ($/kWh)		-0.0019		########				
13									
14									
15	Net Lost Fixed Cost ($/kWh)		0.02491		0.01261				

Delivery Demand Charge Adjustment

Line No.	Customer Classification and Current Rate Designation	(A) Billing Determinants	(B) Proposed Delivery Demand $/kW	(C) E-3 E-4 Discount Factor	(D) Annual Delivery Demand Revenue $/year (B)*(C)*(D)	Customer Classification and Current Rate Designation	(E) Annual Delivery Demand Revenue $/year
1	**Residential**					**C & I Customers**	
2	ECT-2					E-20	
3	Summer	1,969,123	4.004	1.000	7,884,368	E-30	
4	Winter	1,174,921	2.191	1.000	2,574,252	E-32 XS	
5						E-32 S	
6						E-32 M	
7	ECT-2 L					E-32 L	
8	Block 1					E-32 TOU XS	
9	Summer	261	3.682	0.750	721	E-32 TOU S	
10	Winter	911	2.015	0.750	1,377	E-32 TOU M	
11	Block 2					E-32 TOU L	
12	Summer	2,472	3.682	1.000	9,102	E-34	
13	Winter	6,778	2.015	1.000	13,658	E-35	
14	Block 3					E-221	
15	Summer	5,171	3.682	1.000	19,040	**TO BE COMPUTED POST DECISION**	
16	Winter	10,067	2.015	1.000	20,285		
17	Block 4						
18	Summer	58,391	3.682	1.000	214,996		
19	Winter	23,149	2.015	1.000	46,645		
20							
21	ECT-1R						
22	Summer	2,574,758	4.001	1.000	10,301,607		
23	Winter	1,726,284	2.190	1.000	3,780,562		
24							
25	ECT-1R L						
26	Block 1						
27	Summer	79	3.612	0.750	214		
28	Winter	525	1.977	0.750	778		
29	Block 2						
30	Summer	1,259	3.612	1.000	4,548		
31	Winter	3,960	1.977	1.000	7,829		
32	Block 3						
33	Summer	3,341	3.612	1.000	12,068		
34	Winter	7,046	1.977	1.000	13,930		
35	Block 4						
36	Summer	38,349	3.612	1.000	138,517		
37	Winter	16,111	1.977	1.000	31,851		
38							
39	**Total Residential Demand $**				25,076,346	**Total C & I Demand $**	0
40							
41	Estimated Stability Factor				75.0%		75%
42							
43							
44	Estimated Stable Demand Delivery Revenue				18,807,260		-
45							
46	Residential MWh Sold (adjusted)				13,098,283		14,425,069
47							
48	Demand Charge Adjustment ($/kWh)				(0.00144)		-

Excess Basic Service Charge Adjustment

Line No.	Customer Classification and Current Rate Designation	(A) Average Number of Customers	(B) Proposed BSC $/day	(C) Annual BSC Revenue $/year 365*(B)*(C)	Customer Classification and Current Rate Designa	(D) Annual BSC Revenue $/year
1	**Residential**				**C & I Customers**	
2	E-12	449,101	0.390	63,929,527	E-20	135,929
3	ET-1	278,353	0.579	58,825,731	E-30	516,999
4	ET-2	114,450	0.579	24,187,291	E-32 XS	20,570,535
5	ECT-2	38,017	0.579	8,034,323	E-32 S	12,284,498
6	ECT-1R	47,380	0.579	10,013,052	E-32 M	2,166,573
7	ET-SP	108	0.579	22,824	E-32 L	593,030
8	E-12 Low income	36,296	0.345	4,570,574	E-32 TOU XS	48,410
9	ET-1 low income	15,267	0.579	3,226,451	E-32 TOU S	78,679
10	ET-2 low income	8,588	0.579	1,814,945	E-32 TOU M	21,891
11	ECT-2 low income	1,431	0.579	302,420	E-32 TOU L	25,924
12	ECT-1R Low income	998	0.579	210,912	E-34	223,112
					E-35	104,080
					E-221	310,093
13	**Total Residential**	989,989		175,138,051	Total C & I	37,079,753
14						
15						
16	Customer accts/sales			67,807,220		8,464,918
17	Metering			49,235,438		13,972,972
18	Billing			18,765,643		2,342,652
19	Meter Reading			13,931,056		1,739,147
20	Total Customer Mgt Costs			149,739,357		26,519,689
21						
22	Excess BSC Revenue over Customer Mgt Costs			25,398,694		10,560,064
23						
24	"Super" Class MWh Sold (adjusted)			13,098,283		14,425,069
25						
26	BCS Adjustment ($/kWh)			(0.00194)		(0.00073)

Data Source
(A) CAM_WP13 Schedule H-2 Col (B)
(B) CAM_WP13 Proposed BSC Unbundled Rate by Schedule
Total Customer Management Costs STF 3.27 APS 14600 page 6

Annual Lost Fixed Cost Adjustment Calculation

Line No.		"Super" Residential		"Super" C & I Customers
1	Prior Year Prorated "Savings" (MWh)			
2				
3	Prior Year "Savings" (MWh)			
4				
5	MER Verified Savings			
6	2012 (Prorated)			
7	2013			
8	2014			
9				
10	Total "Savings" (MWh)	0		0
11				
12	Prior Year Prorated Distributed Generation Production			
13				
14	Prior Year Distributed Generation Production			
15	Total Distributed Generation	0		0
16				
17	Total "Lost" Energy	0		0
18				
19	Net Lost Fixed Cost ($/kWh)	0.02491		0.01261
20				
21	Total "Super" Class Lost Fixed Cost Revenue	$0		$0
22				
23	Total Lost Fixed Cost Revenue		$0	
24				
25	Clawback for Excess "Savings"			
26	Interest on Clawback			
27				
28	Net Lost Fixed Cost Revenue		$0	
29				
30	Total Company Revenues Prior Year			
31				
32	Total LFCR Adjustment for Current Period			

EXHIBIT
S-5

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 2, 2011

TABLE OF CONTENTS

SCHEDULES

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-11-0224

My testimony reviews Arizona Public Service Company's ("Company") jurisdictional allocation study and the cost of service study. Based upon the Arizona Corporation Commission's Utilities Division's ("Staff") recommended small rate decrease, Staff recommends an across the board allocation of the revenue decrease among the five customer classes.

Staff recommends that the residential class rate decrease be accomplished by reducing the Basic Service Charge. For the general service and water pumping classes the rate decrease should be accomplished by reducing customer and demand charges across the board. For the lighting classes, Staff recommends across the board decreases.

In order to make the low-income and medical program (Riders E-3 and E-4) clearer and easier for customers to understand, Staff recommends that the existing benefits of the program be retained at the current level. To provide a clear measure of the total value of the programs for participants, the existing low-income rate schedules should be eliminated and replaced by larger (offsetting) Riders (E-3 and E-4).

Staff has analyzed the miscellaneous changes to rate schedules proposed by the Company and offers recommendations for additional requirements or improvements.

Finally, Staff recommends that the Company be ordered to perform a rate research program covering a number of issues, including the interaction between decoupling and rate design potential changes in blocks and tiers, and guidelines for the review, adoption and discontinuance of rate schedules and riders.

INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. In this proceeding I submitted testimony in regard to decoupling on November 18, 2011. My qualifications are set forth in that testimony.

DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division ("Staff").

Q. What is the purpose of your testimony?

A. My testimony analyzes Arizona Public Service Company's ("APS" or "Company") jurisdictional and class cost of service studies and offers a proposed revenue allocation between major classes and a proposed rate design.

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should accept the Company's jurisdictional allocation study.
- The Commission should accept the Company's class cost of service study.

- Based on the net revenue decrease developed by Staff, the Commission should accept the revenue allocation proposed by Staff.
- Based on the revenue allocation developed, the Commission should accept the rate design proposed by Staff.
- The Commission should direct the Company to revise its low-income rate design as proposed by Staff.
- The Commission should direct the Company to plan and perform rate research as proposed by Staff.

JURISDICTIONAL ALLOCATION

Q. Why is jurisdictional allocation important?

A. The Company provides services to a number of entities commonly called sale for resale. The Federal Energy Regulatory Commission ("FERC") regulates wholesale transactions. In developing its revenue requirements and before performing any allocation of those requirements among rate classes, the costs (capital and expenses) and revenues from the wholesale customers must be removed or excluded from the jurisdictional revenue requirements process. To develop those exclusions the Company provided its jurisdictional allocations as Schedule GJ.[1] The results indicated that the overall rate of return for the Company was 7.99 percent compared to its jurisdictional rate of return of 8.29 percent and a return of 6.46 percent for all other (non-Commission) customers.

Q. Are there differences between the Company's jurisdictional allocation and the allocation within the Class Cost of Service Study ("CCOSS")?

A. Yes. The most significant difference is the use of a four coincident peaks for June, July, August and September ("4CP") allocator for production plant and related items within the

[1] Attachment ZJF-1

jurisdictional allocation as compared to the use of an average and excess demand ("AED") allocator within the CCOSS.

Q. Is the application of the 4CP method appropriate?

A. The FERC has used a three part methodology[2] to determine if a production allocator should focus on a season or the entire year. I performed this test for the years 2011 through 2015 based on information provided by the Company. Based on this methodology the use of a 4CP allocator at this level is appropriate.

Q. Is the application of an AED allocator appropriate within a class cost of service study?

A. The Commission decided this issue in Decision No. 69663 (June 28, 2007) at pages 70-71 following the litigation of the issue during that case. I have also recommended the use of the AED allocator in a number of other cases and consider its use here appropriate.

Q. Is this allocator difference appropriate?

A. The FERC has required the use of the 4CP allocator[3] and the Company has complied with this requirement and further applies it to its jurisdictional allocation to be "consistent with the allocation method that APS is required to use in its cases before the FERC "and to prevent" the potential for "stranded" costs that cannot be recovered from either jurisdiction."[4] The Company's position is appropriate because it is responding to two different regulatory bodies.

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[2] FERC Docket Nos. EL05-19-002 and ER05-168-001, paragraph 76
[3] Fryer Direct 10:19-23 and APS Response to Staff Data Request ("STF") 3.17
[4] Fryer Direct 10:20

Q. Did you review other aspects of the jurisdictional allocation?

A. I performed a review of the allocations, reviewed the answers to Staff Data Requests, and conducted an informal technical conference with the Company to understand certain aspects of the jurisdictional allocation.

Q. Is the Company's jurisdictional allocation appropriate for its use to develop the CCOSS?

A. Yes it is.

CLASS COST OF SERVICE

Q. Has the Company provided a cost of service study?

A. The Company provided a CCOSS based on the Test Year (twelve month period ended December 31, 2010).[5] This schedule provides the individual class returns and the Index Rate of Return ("IROR") for the Company's five major customer classes.

Q. What is Index Rate of Return ("IROR")?

A. IROR is the ratio of any class' rate of return to the rate of return of the utility. IROR is also called the unitized rate of return in some jurisdictions. It is a useful barometer of how well individual classes and subclasses compare to each other and support the cost of service for the utility as a whole. Ideally, all classes would approach an IROR of 1.0.

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each

[5] Fryer Direct, Attachment ZJF-4, Schedule GE-1

customer class and subclass. A fully allocated cost of service study is intended to enable a commission to allocate revenue requirements among customer classes.

Q. How does a regulator use the cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Additionally, when determining revenue allocation, regulators have a responsibility to consider not only the utility's financial condition and requirements, but also economic, social and other factors that may affect customers.

Q. Are there limitations to a cost of service study?

A. Yes, a cost of service study involves judgment and decisions on the part of the practitioner in making allocations among customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely, and the practitioner must deal with the resulting uncertainty. Therefore, the cost of service study acts as a guide to revenue allocation and can be used to assist rate design.

Q. Did the Company adjust or normalize its revenues?

A. The Company used a 2010 Test Year and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions. The Company adopted pro forma revenue adjustments for weather normalization, customer annualization and the low-income discount program.[6]

[6] Miessner Direct 35:14-20

Q. Have you reviewed the cost of service study presented by the Company?

A. Yes. The CCOSS was provided as Schedule GE-1 and further expanded to include rate classes in Schedule GE-2 for General Service and GE-3 for residential rates classes.

Q. Did you review other aspects of the CCOSS?

A. I performed a review of the allocations, reviewed the answers to Staff Data Requests, and conducted an informal technical conference with the Company to understand certain aspects of the CCOSS.

Q. Is the Company's CCOSS appropriate for its use as a guideline to develop a revenue allocation proposal?

A. Yes, it is.

Q. What are the relative positions of the various rate classes and subclasses?

A. As a high level indicator, I use the IROR based on the return of the ACC Jurisdiction at 8.29 percent. As shown in Schedule GE-1, the General Service and Dawn to Dusk customer classes are providing an above average return, while the residential, water pumping and street lighting classes are providing below average returns.

As shown in Schedule GE-3, the Residential E-12 rate schedule has a return (7.98 percent, IROR 0.963) below the ACC Jurisdiction, compared to the residential Time of Use ("TOU") rate schedules, which have returns (4.09 percent to 5.35 percent, IROR 0.591 to 0.645) well below the ACC Jurisdiction.

As shown in Schedule GE-2, all of the general service rate classes are providing a return above the ACC Jurisdiction with the exception of the House of Worship (Schedule E-20), which has a return (3.98 percent, IROR 0.480) well below any other class or subclass. Within the general service rate schedules, the TOU schedules have higher returns (and IROR) than their non-TOU counterparts.

REVENUE ALLOCATION

Q. What principles do you use to allocate revenue among rate classes?

A. I use the following principles:

- The individual rate classes (in this case residential, general service, water pumping and lighting) should be gradually moved toward an IROR of 1.000 over one or more rate cases depending on the frequency of rate cases and the distance of the class' IROR from 1.000.
- There should be an upper bound of 150 percent for any class' percentage increase in revenue compared to the overall percentage increase in revenue.
- There should be a lower bound of 50 percent for any class' increase compared to the overall increase.
- In the case when a company receives a decrease in revenue requirements, no class should receive a rate increase.

Q. Does the recommended net revenue decrease proposed complicate the revenue allocation process?

A. The net revenue decrease of $7,443,000 recommended by Staff witness Ralph Smith is a small percentage of the total revenue collected and therefore great changes to the existing rate structure cannot be accomplished. The positive side to this predicament is that the proposed net revenue decrease will have a limited effect on customers.

Q. In light of the small decrease, what revenue allocation between rate classes do you recommend?

A. Due to the small level of the Staff's recommended decrease, I suggest that the decrease be allocated "across the board" on a revenue basis. This proposed revenue allocation avoids the potential for customer confusion when the rate order details a revenue reduction but a class receives an increase. My recommended revenue allocation for the five customer classes is shown in Attachment HS-6.

Q. If the Commission ultimately decides that a revenue increase is appropriate what revenue allocation would you recommend?

A. Using my revenue allocation principles and applying them to this case, I found that no significant movement of IROR could be accomplished without a disproportionate percentage change on the five customer classes. Further, the water pumping and lighting customer classes are small in comparison to the residential and general service customer classes, which balance each other during revenue allocation. Therefore, my revenue allocation would be determined by the 150 percent and 50 percent principles. If the Commission were to award the Company a revenue increase very different from the Staff recommendation, my revenue allocation principles are still applicable.

RATE DESIGN

Q. What underlying principles do you use for rate design?

A. For residential and small general service customers, I lean towards simplicity where possible. This would include a limited number of rate schedules and riders. I recognize that one rate schedule does not fit all customers and that schedules that limit or shift peak consumption have real value both for customers and for system planners.

In recognition of the implementation of advanced metering infrastructure ("AMI"), I recommend that the Basic Service Charge ("BSC") for similar customers on different rate schedules should be the same, although the transition to parity may take some time. This recognizes that costs are the same for metering regardless of whether the customer chooses a standard rate or a TOU rate. Smart meters have the capability to report consumption by interval, and then the usage by periods is determined by data analysis rather than by meter readings. Thus, the same meter and software can be used to provide meter reading for most rate forms at approximately equal cost.

Q. What changes do you propose for the residential rate class?

A. Due to the very small and negative change in revenue allocated to the residential class, I recommend that the decrease be applied to the BSC. This will provide a visible decrease for every residential customer.

Attachment HS-7 provides the details of my initial residential rate design, which is an equal decrease in the BSC for all five of the Company's non low-income residential rate schedules.

Q. If the Commission ultimately decides that a revenue increase is appropriate, what residential rate design would you recommend?

A. In recognition of the difference in IROR, I recommend that the TOU rate schedules ET-1, ECT-1, ET-2 and ECT-2 receive a higher increase than the non-TOU E-12 rate schedule.

At the same time, I recommend that the BSC for the TOU schedules be moved closer to the BSC for the E-12 rate schedule to start the convergence to one BSC. The Company indicates that AMI continues to be implemented and by the end of 2012 will have over 950,000 customers with smart meters.[7]

The Company provided unit cost data for the BSC charges for the various residential rates.[8] This information contains identical costs for customer accounts/sales, billing and meter reading. The costs for metering are lower ($1.27) for E-12 customers compared to TOU customers. The Company is proposing to narrow the gap between the BSC of each residential rate schedule, but has requested a monthly BSC of $11.86 and $17.61 respectively.[9] The Company explained this difference as its attempt to capture a portion of the distribution transformation charges.[10] This attempt is obvious in APS 14583, where the E-12 rate is assigned 0 percent, the ET-1, 2 are assigned 30 percent, and the ECT-1, 2 are assigned 24 percent of the distribution transformer and secondary revenue requirements.[11] The Company discussed this during the informal technical conference and acknowledged that the 0 percent allocation was made to avoid too large of an increase for E-12 customers.

I do not support the Company's inclusion of varying portions of the distribution transformation costs in the BSC. The Company has provided no evidence to support this transfer of demand costs into a customer component or to explain why the percentage varies among classes and subclasses. While my BSC recommendation may make the residential revenue slightly less stable, this is counteracted by Staff's proposed Lost Fixed Cost Revenue mechanism.

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[7] APS AMI Plan Biannual ACC Report page 1 (September 9, 2011)
[8] APS Response to STF 3.27 APS 14583
[9] Miessner Direct 8:18
[10] Miessner Direct 8:7-11
[11] APS Response to STF 3.27 APS 14583

Q. Have you reviewed the Company's proposal for an experimental residential peak rate?

A. The Company is proposing Rate Rider Schedule PTR-RES as an experimental program. This program offers a "carrot" for customer participation and does not pay for the customer's commitment unless the Company requests, and the customer provides, a critical period load reduction. The Company has provided its calculation of the $0.25 per kWh rebate.[12] The program specifies that there will be at least 6 and a maximum of 18 five-hour events annually. This should test a customer's commitment to respond to the critical peak rather than serving as a rate discount.

Experimentation that can lead to more responsive rate forms should be encouraged; however, the approval of this program should require the Company to provide details on its proposed methods of analysis, solicitation, and selection of customers as well as the customer education it will offer before entry into the program (and for customers in the program) as the critical peak concept and baseline estimation protocol may be complex.

There is a discrepancy between the Company's testimony and the proposed rate rider schedule. The testimony indicates that this rider is available to E-12 and ET-2 customers[13], while the tariff sheet indicates that it is available to customers served under Rate Schedule ET-2 and also requires the customer to have an Advanced Metering Infrastructure meter[14]. I recommend that the tariff sheet be amended to allow E-12 customers (properly metered) to participate. This will also allow the Company to determine if participation and performance are different between E-12 and ET-2 customers.

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[12] Workpaper CAM_WP3
[13] Miessner Direct 13:15
[14] Miessner Direct Attachment CAM-5

Q. Have you reviewed the Company's proposal to revise the low-income (Residential Service Energy Support) and medical (Medical Care Equipment Support) programs?

A. As a result of my review, I recommend a number of changes to simplify the structure of the program and reduce potential confusion upon entry into and exit from the program. These changes should be implemented regardless of the level of the revenue decrease (or increase) finally determined, as the revisions are approximately revenue neutral.

I recommend that the Company should implement the low-income or medical "discount" as a single line item on the customer's bill using the "regular" residential rate schedules rather than as separate low-income rate schedules and an accompanying E-3 or E-4 rider. At present, a low-income customer can see the value of the E-3 rider discount, but cannot see the value of the reduced charges within the low-income rate schedules.

As presently implemented, the E-3 and E-4 programs overlap the low-income rates, which are different from the comparable rate schedules. When a customer becomes eligible for the E-3 or E-4 program, their rate schedule changes and a rider is also applied.

To highlight the total value of the programs provided by other customers, a simpler/clearer method would allow a customer to continue on their existing residential rate schedule and then have all of the benefits be provided through a rate rider. Customers also would not need any explanation of why they had been moved to a new (higher cost) rate schedule when their E-3 eligibility ceased. Increasing the value of the E-3/E-4 riders and eliminating the five low-income versions of the residential rates will provide simplicity and clarity to this area of the Company's tariff.

Q. The Company has proposed applying the PSA-1 and DSMAC adjustors to the low-income rate schedules[15]; do you agree with this proposal?

A. The Company's argument to include the PSA-1 and DSMAC adjustors for these customers is supported by concepts of rate clarity and simplicity. Additionally, as the PSA can and does go negative at times, the existing methodology that ignores the PSA now negatively impacted customers. For these reasons, the Company's position is appropriate. However, the E-3 and E-4 discounts should be applied to the total bill that includes the adjustors.

Q. Have you been able to analyze the impact of your proposal to eliminate the low-income rate schedules and increase the value of the E-3/E-4 riders?

A. Due to the interrelationship of the Company's existing five residential rate schedules and the five residential low-income rate schedules along with the E-3 and E-4 discount riders, the modeling and revenue proof are complicated. I approached the Company and they cooperatively modified the Company's residential class revenue proof to allow a review of its proposal along with the ability to evaluate other alternatives. The values of the individual portions of the low-income rate schedules and the E-3/E-4 riders were derived from this modified revenue proof.

Starting with the Company's revenue proof, I first compared the existing residential rate schedule to the corresponding low-income rate schedule using the billing determinants for participants. The results of this calculation are shown on Attachment HS-8 (page 1). This "hidden" portion of the program provides Test Year benefits of over $9,938,000 for E-3 customers and over $85,000 for E-4 customers.

[15] Miessner Direct 11:1-3 and 12:16-17:9

Again using the revenue proof, I extracted the value of the rider E-3/E-4 discounts. The results of this calculation are shown on Attachment HS-8 (page 2). This "visible" portion of the program provides Test Year benefits of over $10,652,000 for E-3 customers and over $148,000 for E-4 customers.

I calculate the present Test Year value/cost of excluding E-3/E-4 customers from the PSA-1 and DSMAC as over $-4,086,000 and $1,962,000 respectively (Attachment HS-8 (page 3)).

Taken together, the total Test Year value to E-3/E-4 customers is over $18,700,000. This total amount would flow through the System Benefits calculation.[16] Because the System Benefits calculation applies to all customers and is calculated on an energy basis, the treatment is consistent with Decision No. 71448 that orders that the E-3 & E-4 discount should be spread across customer classes on a per kWh basis. The impact of the PSA-1 and DSMAC adjustors within the System Benefits calculation is offset by including all customer usage in these two adjustors.

Q. The Company has proposed closing the gap between the standard residential rates and the respective low-income rate schedule by approximately 3.0 percent – 3.6 percent.[17] Do you support this recommendation?

A. No. The Company has not provided evidence to support closing the gap. At this time of adverse economic conditions, I do not recommend that the differential established in the last case be reduced. Further, implementation of this Company recommendation would subject low-income customers to a net revenue increase unlike all other customers.

[16] APS Informal Data Response 2 APS 14996 page 5
[17] Miessner Direct 10:17-25

Q. How do you propose to modify the structure of the E-3 and E-4 riders?

A. I propose to retain the "tiered and capped" construction of the discounts to encourage customers to control their overall usage while providing the discounts that previous decisions have established. To maintain the same approximate discount levels for customers within each tier at present Test Year rates, the discount percentages and caps would change as shown in Attachment HS-8 (page 4). I address the future determination of the tiers further in my testimony. The discount percentages and caps may change depending on the final magnitude of the revenue decrease/increase.

Q. What changes do you propose for general service customers?

A. I recommend a lower emphasis on volumetric rates, and I recommend moving the BSC and demand rates towards cost-based rates. To reflect the small decrease, I recommend that the BSC (customer) and demand rates be reduced across the board.

Q. Is the Company's proposal to modify Rate Schedule E-32 L appropriate?

A. The Company is proposing to eliminate the first tier energy charge and shift the implicit demand now collected by the volumetric charge into the demand portion of the rate.[18] This transition is appropriate, as it will stabilize revenue and decrease the need for a decoupling mechanism. The implicit demand was equal to $8.382 per kW-month.

However, the Company should account for the incremental revenue resulting from the addition of an 80 percent demand ratchet to rate schedule E-32 L. The Company has added a demand ratchet with the same wording as the existing E-32 XL provision. The revenue proof for E-32 L does not show any incremental demand ratchet revenue.

[18] Miessner Direct 18:8

Q. What changes should be made to Rate Schedule E-20 House of Worship?

A. Rate Schedule E-20 (House of Worship) should be unfrozen for one year from the date new rates in this case are implemented. The Company is proposing a number of changes to the general service rate schedules. To avoid concerns that a customer may be locked into an inappropriate rate schedule, reopening this schedule for a limited period of time would be a reasonable policy decision.

Unlike all other general service rates, the E-20 rate schedule has a very low IROR, and if a revenue increase had been determined, I would have recommended a higher revenue allocation for this schedule as compared to other general service schedules.

Q. Is the Company's recommendation to remove the monthly contract minimum charge provisions for small and medium general service schedules E-32 S, E-32 M, E-32 TOU S and E-32 TOU M appropriate?

A. The Company suggests that the minimum charge provision is unneeded to protect the Company's investment in wires capacity, "an investment that is typically not fungible to other customers."[19] The Company argues that this proposal will simplify rates and reduce bill inquiries without unduly creating a risk of shifting wires costs to other customers. The Company proposes this change for small and medium general service customers. Arguably, these customers are more likely to share some facilities than larger customers. In the Test Year, few customers were subject to this provision.[20] In the interest of rate simplicity and clarity, I support this proposal.

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[19] Miessner Direct 17:10

[20] APS Response to STF 7.2 and 8.1

Rate Rider Schedule E-54 removes the alternative minimum bill for seasonal agricultural customers.[21] With the approval of the removal of the minimum bill provisions discussed above, this rider should be made applicable for Rate Schedule E-32 L customers as the minimum bill provision still applies to this schedule.

Rate Rider Schedule E-53 is designed to remove the alternative minimum bill for sports field lighting.[22] With the approval of the removal of the minimum bill provisions discussed above, this rider can be removed and existing customers will be subject to the BSC for their chosen rate, which represents the charges necessary to service these customers.

Q. Have you reviewed the Company's proposal to establish an Experimental Rate Rider Rate Schedule AG-1?

A. Yes. The Company is proposing this experimental rate for very large customers with demands over 10 MW.[23] I recommend the adoption of this experimental rate program with a requirement that the Company provide a structured, predefined program to report on the impact of this rate. Reports should be made quarterly and indicate the level of customer adoption, the rates attained by the program, the savings afforded to participating customers, the costs to the Company to establish and maintain this service for participating customers, the profitability of this rate, and the impact of this rate on the costs and rates of non-participants, including impacts on other rates and adjustors such as the PSA.

[21] Miessner Direct 19:5
[22] Miessner Direct 18:20
[23] Miessner Direct 20:13

The tariff sheet indicates "the Company will subsequently contract with the Generation Service Provider on behalf of the customer for the specified power and manage the contract for the customer."[24] To protect all other customers, the approval of this experimental rider should require the Company not to commit to purchase, accept or take any power or incur any costs should the AG-1 customer decrease its consumption.

Q. Have you reviewed the Company's proposal to establish a Rate Rider Rate Schedule IRR?

A. Yes. The Company is proposing this interruptible rate for extra-large customers that will pay them capacity and energy payments for interruptible load as filed in Docket No. E-01345A-10-0250.[25] This proposal require at least two interruptions annually, which should minimize participation of customers who are focused on lower costs, rather than providing load curtailment. I recommend that the adoption of this rate rider should include a requirement that the Company provide a structured, predefined program to report on the impact of this rate. Reports should be made to Staff quarterly and indicate the level of customer adoption, the amount, time and impact of interruptions under this program, the payments made to participating customers, the Company's costs to establish and maintain this service for participating customers, the profitability of this rate, and the impact of this rate on the costs and rates of non-participants, including impacts on other rates and adjustors such as the PSA.

Q. Is the Company's proposal to modify Rate Schedules E-221 Water Pumping Service and E-221-8T Water Pumping Service T.O.U. appropriate?

A. The Company is proposing to change the on-peak hours for schedule E-221-8T to 11 AM to 9 PM to better reflect the Company's on-peak load and be consistent with other general

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[24] Miessner Direct Attachment CAM-7 Page 1
[25] Miessner Direct 20:13

service rates.[26] Under the present rate schedule, the customer can choose 8 consecutive hours between 9 AM and 10 PM. This allows a customer to declare the period of 5 PM and later as off-peak. A water system that was operated to achieve reductions ending at 5 PM might produce its greatest impact shortly after that period. I recommend the adoption of this proposal in order to ensure that a customer does not shift load into the period shortly after 5 PM to the detriment of the Company's energy costs during peak time.

The Company is proposing to remove the option for a water pumping customer to select one day per week as an off-peak day. This present provision has a "buy through" discount and penalty arrangement. Examination of the Company's revenue proof indicates that the total discounts during the test year were approximately $12,500, but penalties assessed were approximately $4,500.[27] I recommend the adoption of this modification.

To reflect the small decrease, I recommend that the BSC (customer) and demand rates be reduced across the board.

Q. Is the Company's proposal to modify Rate Schedules E-47 Dusk to Dawn Lighting Service and E-58 Street Lighting Service appropriate?

A. The Company is proposing to add a trip charge to this rate[28] that would apply when the Company is not the responsible party for maintaining the lights and the Company is requested by the customer to disconnect or reconnect service.[29] The addition of a trip charge is a means of protecting other customers from costs caused by the requests of a single customer. I recommend the adoption of this charge.

[26] Miessner Direct 24:6
[27] Work Paper CAM_WP13 sheet E-221
[28] Miessner Direct Attachment CAM-8
[29] Miessner Direct 23:14

For lighting equipment greater than $25,000, the Company is proposing a financial liability agreement as a special provision for E-47, but this provision is not included in E-58. I recommend the adoption of this measure for both schedules[30] which will reduce risks for other customers.

To reflect the small decrease, I recommend that the lighting rates be reduced across the board.

Q. The Company is proposing a number of miscellaneous tariff changes. Have you reviewed those proposals?

A. Yes. The Company proposes to split the existing rate schedule E-36 into two tiers with a break point at 3 MW.[31] This schedule applies to merchant generators that require starting and station service. I recommend the adoption of this modification; however, the Revenue Cycle Charges for E-32 M do not seem to fit "between" the XS and L charges and the Company should confirm the proposed charges.

The Company is proposing to allow participation for wind, geothermal, biomass and biogas in addition to the existing solar generation under Rate Schedule SC-S (retitled E-56 R).[32] The redlined tariff sheet does not show the requested change.[33] The intent appears to be to encourage these additional forms of renewable energy. I recommend that the Company provide a revised sheet for consideration, and assuming no significant changes, I support this change.

[30] The testimony implies both schedules but E-58 does not include that provision (Miessner Direct 24:1)
[31] Miessner Direct 26:11
[32] Miessner Direct 26:5
[33] Work Paper CAM_WP14 sheet 181

In the interest of rate simplification, I support the Company's proposal to discontinue Rate Schedules E-40, Solar-2 and Solar-3. One, none and two customers use these rate schedules respectively.[34]

Q. Have you reviewed Rate Rider Schedule CPP-GS?

A. Yes. Rate Rider Schedule CPP-GS should be revised to eliminate the energy discount for any month that a customer fails to provide a load reduction during a critical event as defined in its load reduction plan. If the customer fails to provide the load reduction for two months within an annual summer period, then the customer should be removed from the program and the rider should not apply. The present construction of the rider provides for a discount on all energy during the June through September billing cycles along with a further payment for critical peak price reductions during a critical event. There is no penalty for not providing a load reduction during a critical event. Adding this penalty will preclude customers from "gaming" this rider.

Q. Do you have any overall recommendations as a result of your decoupling and rate design review in this case?

A. The Company has not conducted any specific rate research other than as part of its usual rate design process.[35] As recommended in the Staff decoupling testimony, the Company should plan and perform rate research. The Company has a wide range of rate schedules, including some that are frozen, and it continues to experiment with new concepts. The Company should be required to define for the Staff a rate research plan within three months of a Decision in this case, complete the plan within an additional nine months, and then provide the results to Staff. The plan should at a minimum include:

[34] Miessner Direct 24:23
[35] APS Response to STF 3.26

- Reviewing or justifying the existing blocks and tiers within rate schedules in light of recent load research, appliance saturation, new uses such as heat pump water heaters, energy efficient computers, televisions and the penetration of energy efficient appliances
- Providing the timing or triggers for the elimination of existing frozen rates
- Determining analysis methods and standards for making an experimental rate permanent or withdrawing that rate
- Determining whether adjustors should be embedded within, partially embedded or separate from existing rates
- Analyzing whether more complicated and/or varied rate forms are productive and understood by customers
- Determining if, when and how distribution (delivery) rates might shift from volumetric to demand based to eliminate the need for a decoupling mechanism

Q. Does this conclude your testimony?

A. Yes it does.

Testimony - Howard Solganick

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.

Attachment HS-6

Staff Revenue Allocation

Line No.	Customer Classification	(A) Present Rates 1, 2 ($000)	(B) Proposed Increase 3 ($000)	(C) % (B) / (A)
1	Residential	1,470,134	(3,814)	-0.26%
2				
3	General Service	1,342,599	(3,483)	-0.26%
4				
5	Irrigation/Water Pumping	26,669	(69)	-0.26%
6				
7	Outdoor Lighting	20,999	(54)	-0.26%
8				
9	Dusk to Dawn Lighting Service	8,457	(22)	-0.26%
10				
11				
12	Total Sales to Ultimate Retail Customers	2,868,858	(7,443)	-0.26%

NOTES TO SCHEDULE:
1) Base Revenues under Present Rates reflect adjusted test year revenues including Company proforma adjustments.
2) Present Rates - base revenues include transmission.
30 Revenue Increase from Staff witness Smith

Residential Rate Design

Line No.		(A)		
1	Proposed Residential Increase		$	(3,814,133)
2				
3		Average		
4	Customer Classification	Number of		
5	and Current Rate Designation	Customers		
6				
7	Residential			
8	E-12	449,101		
9	ET-1	278,353		
10	ET-2	114,450		
11	ECT-2	38,017		
12	ECT-1R	47,380		
13	ET-SP	108		
14	E-12 Low income	36,296		
15	ET-1 low income	15,267		
16	ET-2 low income	8,588		
17	ECT-2 low income	1,431		
18	ECT-1R Low income	998		
19				
20	Total Residential	989,989		
21				
22	Total Residential Customer Days	361,345,985		
23				
24	BSC - Increase per Residential Customer Day			(0.010555)

Data Source
(A) CAM_WP13 Schedule H-2 Col (B)

Line No.	Program	Tier	E-12 L	ET-1 L	ET-2 L	ECT-2 L	ECT-1R L	Subtotal
			Present Residential Rates vs. Present Low Income Rates					
1	**E-3**							
2		**Tier 1**	516,781	88,353	37,499	3,547	3,186	649,366
3		**Tier 2**	1,270,607	446,242	223,824	25,729	17,325	1,983,727
4		**Tier 3**	998,991	584,618	346,690	43,723	30,159	2,004,181
5		**Tier 4**	1,832,965	1,805,180	1,197,430	282,807	182,733	5,301,115
6								
7	**E-4**							
8		**Tier 1**	13,697	3,167	1,280	235	174	18,553
9		**Tier 2**	16,005	7,120	3,752	924	630	28,431
10		**Tier 3**	5,396	6,365	3,231	886	673	16,551
11		**Tier 4**	5,555	8,136	5,019	1,802	1,545	22,057
12								
13	**E-3**	**Subtotal**	4,619,344	2,924,393	1,805,443	355,806	233,403	9,938,389
14	**E-4**	**Subtotal**	40,653	24,788	13,282	3,847	3,022	85,592
15								
16		**Total**	4,659,997	2,949,181	1,818,725	359,653	236,425	10,023,981

Present Discounts Below Current Low Income Rates

E-12 L	ET-1 L	ET-2 L	ECT-2 L	ECT-1R L	Subtotal
1,615,269	273,617	115,224	11,023	9,984	2,025,117
2,576,381	895,863	444,950	51,891	35,310	4,004,395
1,089,806	631,143	370,263	47,451	33,103	2,171,766
731,752	915,344	587,429	136,113	80,871	2,451,509
42,738	9,786	3,918	731	544	57,717
32,423	14,274	7,439	1,862	1,285	57,283
5,884	6,865	3,444	961	738	17,892
2,807	6,054	3,702	1,428	1,221	15,212
6,013,208	2,715,967	1,517,866	246,478	159,268	10,652,787
83,852	36,979	18,503	4,982	3,788	148,104
6,097,060	2,752,946	1,536,369	251,460	163,056	10,800,891

Rate Differential	Low-Income Discount	PSA-1	DSMAC	Total Program Discount
649,366	2,025,117	-246,350	118,299	2,546,431
1,983,727	4,004,395	-839,243	403,009	5,551,888
2,004,181	2,171,766	-847,015	406,741	3,735,673
5,301,115	2,451,509	-2,117,506	1,016,837	6,651,955
18,553	57,717	-7,894	3,791	72,167
28,431	57,283	-12,057	5,790	79,447
16,551	17,892	-7,289	3,500	30,654
22,057	15,212	-9,618	4,618	32,270
9,938,389	10,652,787	-4,050,115	1,944,886	18,485,947
85,592	148,104	-36,857	17,699	214,538
10,023,981	10,800,891	-4,086,972	1,962,585	18,700,484

Total Base Revenue @ Non "L" Rates	**Tier % Discount**	Customer Bills	Maximum Discount
5,712,158	44.58%		
17,385,244	31.93%		
17,516,797	21.33%		
44,747,397		188,577	$ 35.27
162,847	44.32%		
248,751	31.94%		
144,358	21.24%		
189,605		584	$ 55.26
85,361,596			
745,560			
86,107,157			